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Energy Perspectives™

Rougher Seas Ahead

Special edition | Issue 8

Strategy | Consulting | Digital | Technology | Operations

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Introduction

Welcome to the 8th edition of Energy Perspectives, a special edition in at least two ways.

First and foremost, its release coincides with a pivotal point in history. Our industry is experiencing its most severe downturn in decades and all those involved face the difficult and painful prospect of having to quickly transform their business to remain relevant and prosperous in a radically different environment. But that's not all. We've also entered a period in which CO_2 emissions' effect on Earth's climate is assuming greater prominence in the world's economies, as punctuated by the COP21 agreement last December. The implications for hydrocarbon products and the companies that produce them will be significant and far reaching.

For the editorial committee and authors, this edition is also special because it's the first Energy Perspectives published since Accenture's acquisition of SBC.

By joining forces, SBC and Accenture have created a new consulting platform that's uniquely positioned to help the industry respond to today's challenges. This platform—which provides end-to-end transformation support from strategy and planning through implementation—combines the best of both companies: business consulting know how and experience; research and thought leadership capabilities; the knowledge capital SBC has developed in E&P during the past 12 years; and Accenture's broader set of functional, technical and digital capabilities.

The 8th edition of Energy Perspectives is a product of and response to this new backdrop. It features eight articles and one interview that provide valuable insights on current developments within the industry, the implications for E&P companies and other related players, and actions to take now to weather the storm and devise sustainable long-term strategies.

The first article explores in detail the changes in supply-demand dynamics and the two relatively durable trends they are shaping: reversion to a tighter, lower long-term price band; and rapid, short-term movements within this band. These trends will require oil and gas companies to think much differently about their strategies and operations in the next several years.

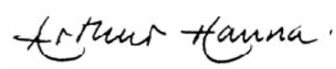
Considering the societal and environmental factors further constraining demand in the medium to long term, the second article examines the significance and consequences of the COP21 agreement relative to CO_2 emissions—particularly, energy cost and affordability (especially for developing nations) and states' reactions to the prospect of stranding their valuable resources.

The next two pieces focus on how the crisis affects countries holding hydrocarbon resources and how these countries can adjust their strategies and policies to continue to attract investment while sustainably developing their resources. An interview with the Minister of Petroleum and Natural Resources for Timor-Leste provides a firsthand perspective.

The following four articles examine in detail some of the strategic and operational issues operators face (including those specific to North American LTO operators) and the structural, sustainable options they should consider instead of the typical immediate but often short-sighted responses: selling assets, cutting investments, slashing headcount, and squeezing suppliers.

Rounding out this edition is a piece that takes a longer-term look at the transformative potential of analytics (big data) and digital capabilities in the upstream oil and gas industry.

We hope you find this 8th edition of Energy Perspectives informative and thought provoking. It truly reflects not only the authors' passion for the industry, but also the powerful insights, experience and capabilities the newly formed Accenture Strategy Energy Upstream group, SBC's successor, brings to the industry. Our global team, with its unique upstream expertise enhanced by the broad range of Accenture Strategy capabilities, provides the distinctive strategic insights, effective implementation support, and world-class analytical and digital capabilities that can help oil and gas companies survive and thrive in these most challenging times.



Arthur Hanna
Senior Managing Director
Accenture Strategy,
Energy

Jean-Marie Rousset
Managing Director
Accenture Strategy,
Energy, Upstream Lead

SECTION 1

Rougher Seas Ahead:

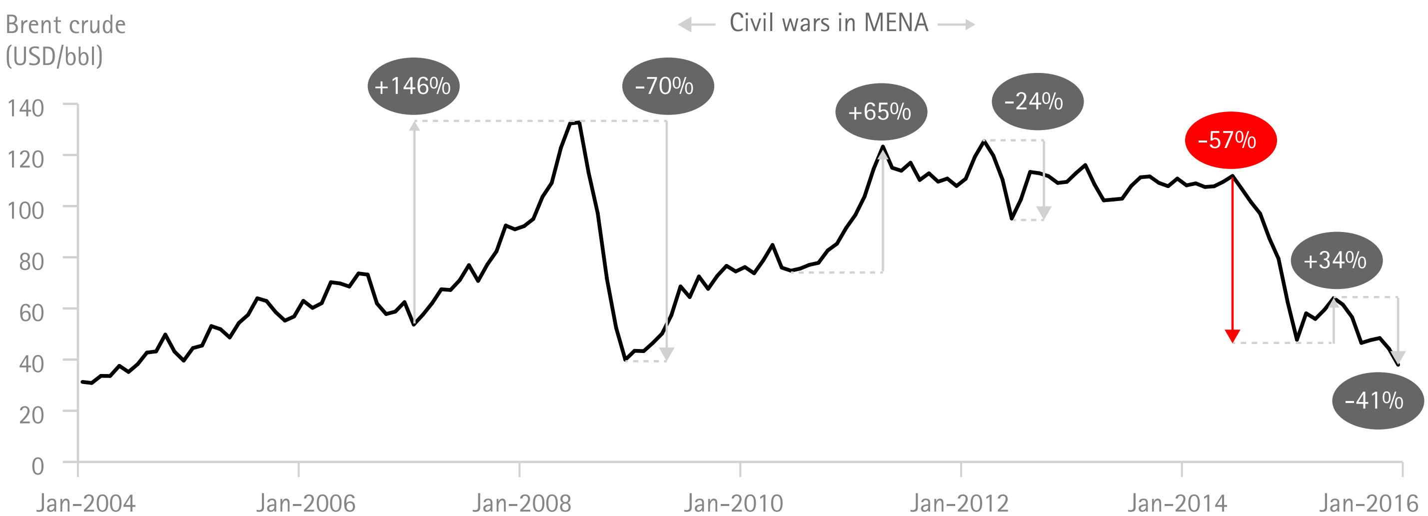
What the current supply-demand dynamics and consequent crude oil price collapse tells us about future crude oil market volatility

Authors: Muqsit Ashraf, Stephane Lhoste, Nicole Lu and Manas Satapathy

Crude oil prices, influenced by several mercurial factors (Figure 1), are notoriously volatile and difficult to forecast. In fact, those who try often are said to be playing a fool's game. That's clearly evident in the past eight years, as economic cycles and geopolitics (especially the events of the past 12 to 18 months) have set in motion a wild ride that currently has oil near prices not seen in more than a decade.

However, while prices will remain volatile, there is something fundamentally different at work this time around. The market can call it "lower for (much) longer," "a new normal," or some other catchy reference. But the fact is, we have on our hands a supply-demand picture that's shaping two relatively durable trends: one, reversion to a tighter, lower long-term price band; and two, rapid, short-term movements within this band. These trends and their implications will require oil and gas companies to think much differently about their strategies and operations in the next several years.

Figure 1: Crude oil is inherently volatile



Source: IEA

Structural shift 1

Tighter, lower long-term price band

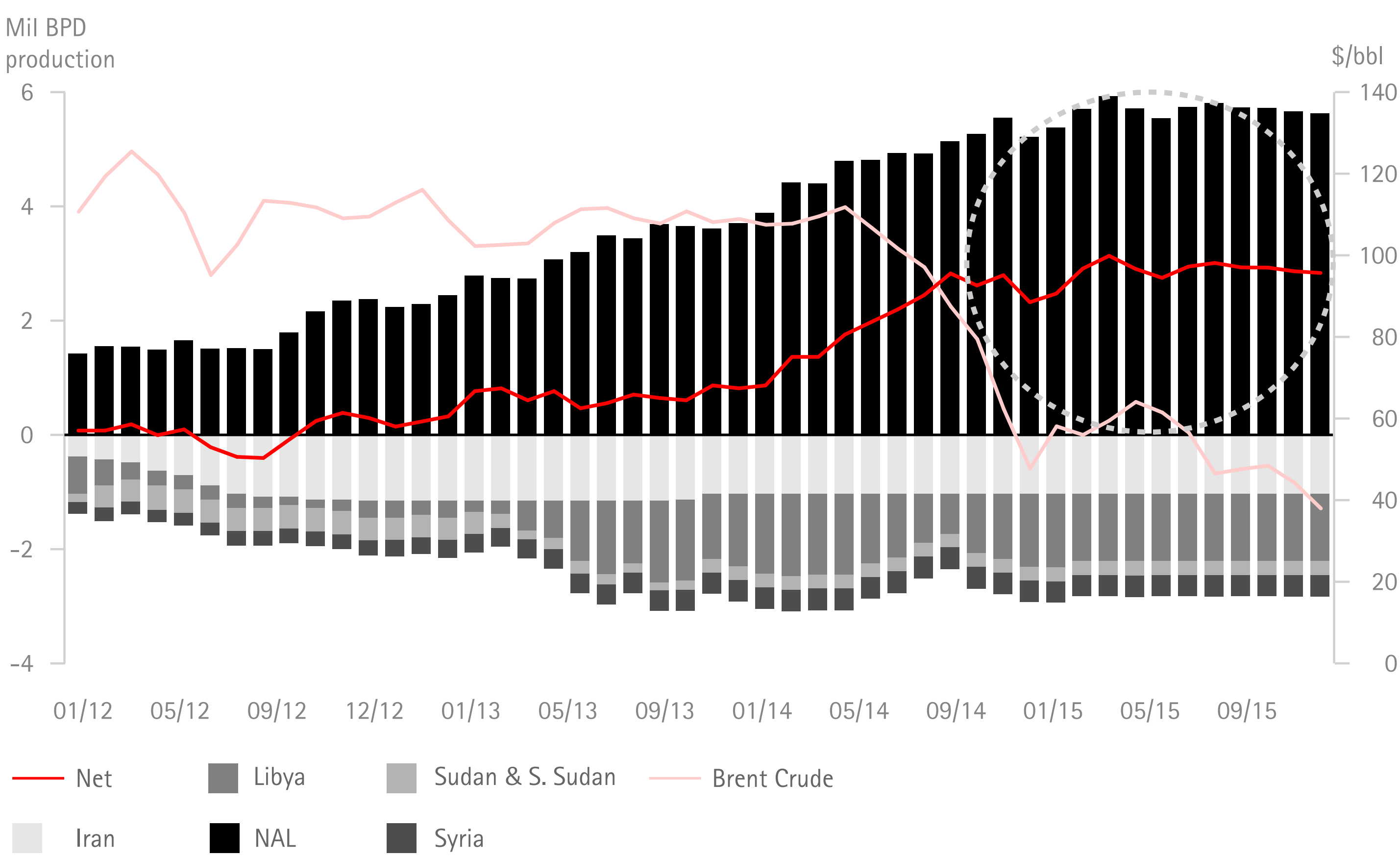
Better to accept the shift than to wait for a turnaround

Much has been written about the first trend, although most commentaries focus on how long it will take for oil prices to reverse their precipitous slump. While $30/barrel prices (or below) are not sustainable, our work suggests that a sea change in industry supply dynamics—coupled with a somewhat less seismic but still significant shift in demand—foretells a tighter and lower-price band over the long haul. And the headwinds anytime there is a meaningful uplift in prices will be severe enough to bring them back.

Relentless supply deluge

From 2003 through 2011, oil markets were relatively tight because demand growth exceeded supply growth. The exception was 2009, when demand briefly collapsed because of global recession. Around 2010, North American LTO emerged, but this small supply increase was overshadowed by supply shortages in Libya, Syria, Iran and Sudan (due to nuclear ban in Iran and civil wars in other MENA countries). North American production increased at a brisk pace: from 0.4 million bpd in 2010 to nearly 4.5 million bpd by mid-2014. This boost more than compensated for the shortages in MENA countries, creating the oversupply that caused prices to crater starting mid-2014 (Figure 2).

Figure 2: Continued oversupply

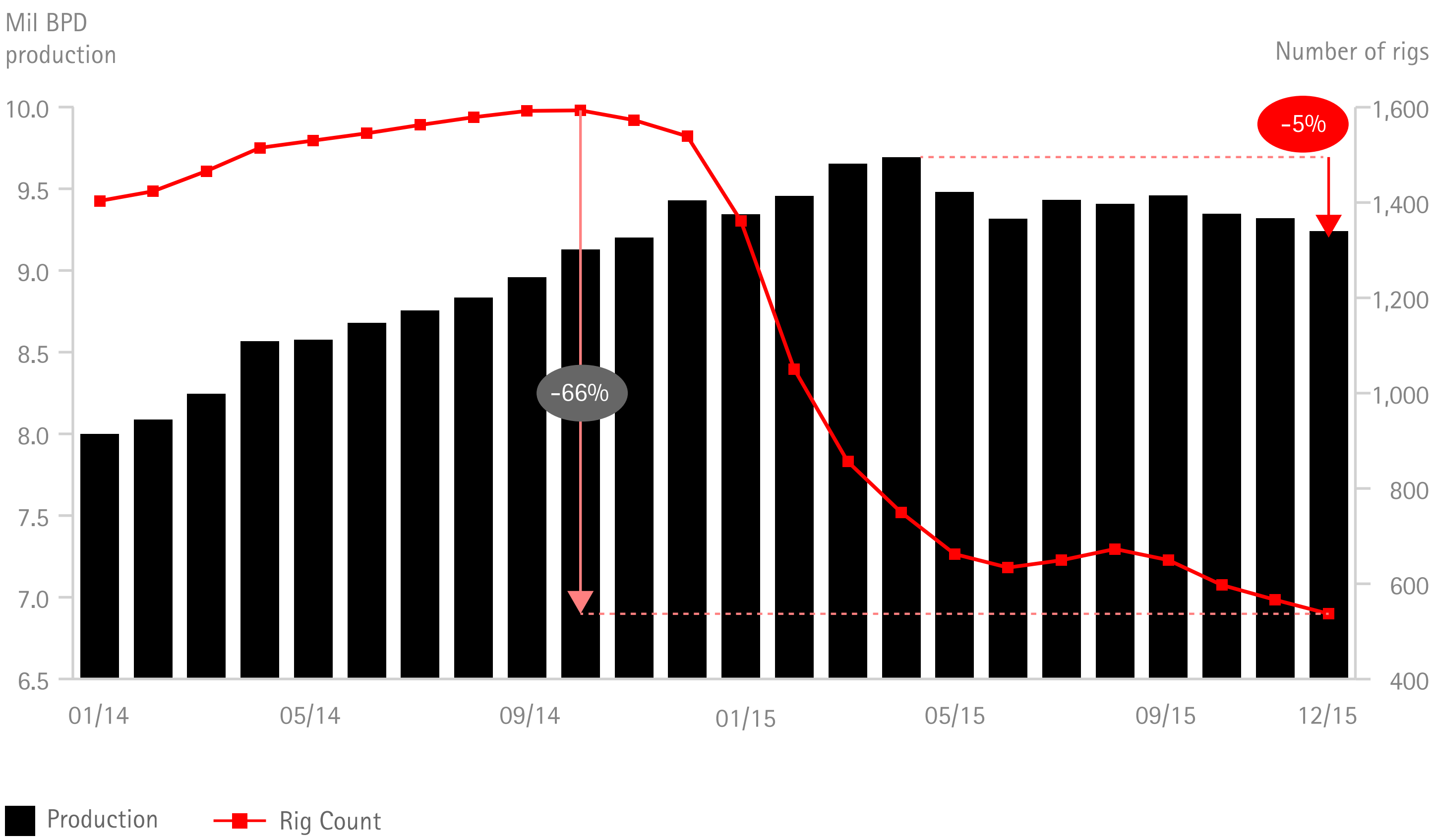


Source: EIA, Accenture Strategy, Energy analysis

The world expected the typical response to restore order: OPEC cutting production and reducing supply. But that didn't happen. Saudi Arabia realized OPEC's ineffectiveness in a loose market and decided to preserve its market share, which only has further loosened the oil markets. Excepting projects already in development (such as Oil sands), operators were forced to put the brakes on high-cost production around the world. One of the biggest targets has been North American LTO: From its peak in June 2014, rig count has dropped about 66 percent.

Yet production has barely budged—it fell only 5 percent (Figure 3)—revealing not only the resiliency of the North American LTO but also the economics of this relatively new source of production. Although LTO has not caught on outside North America, a large share of production could come online at about $60 to $70/bbl. As Argentina and China fully explore their unconventional land production, and the lifting of the ban on Iran enables that country to bring to market an additional 0.5 million to 1 million bpd, even more supply is created.

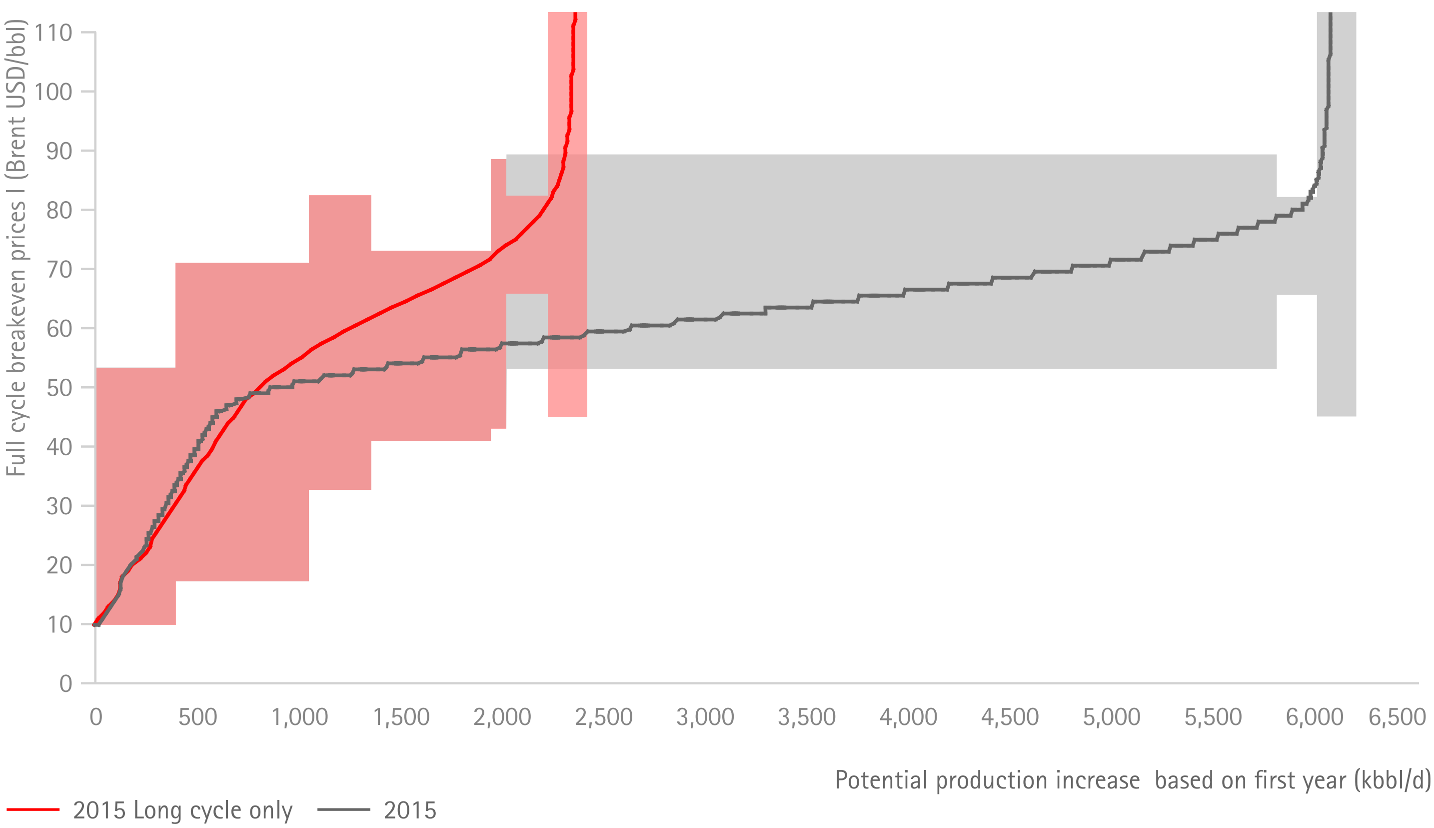
Figure 3: Rig count decline precipitous but production relatively unchanged



Source: BHI, Accenture Strategy, Energy analysis

In short, crude inventories around the world are systematically increasing; and given the desire of OPEC and other large players such as Russia to maintain their market share, the markets most likely won't tighten anytime soon. Even if we see brief periods of market tightening, the supply deluge is real. The market needs to grasp the new reality that huge tranches of production could come online very quickly as soon as the markets tighten. In other words, the incremental supply curve (new supply that comes online every year) has flattened significantly (Figure 4).

Figure 4: Flattening of supply curve due to short cycle source of production



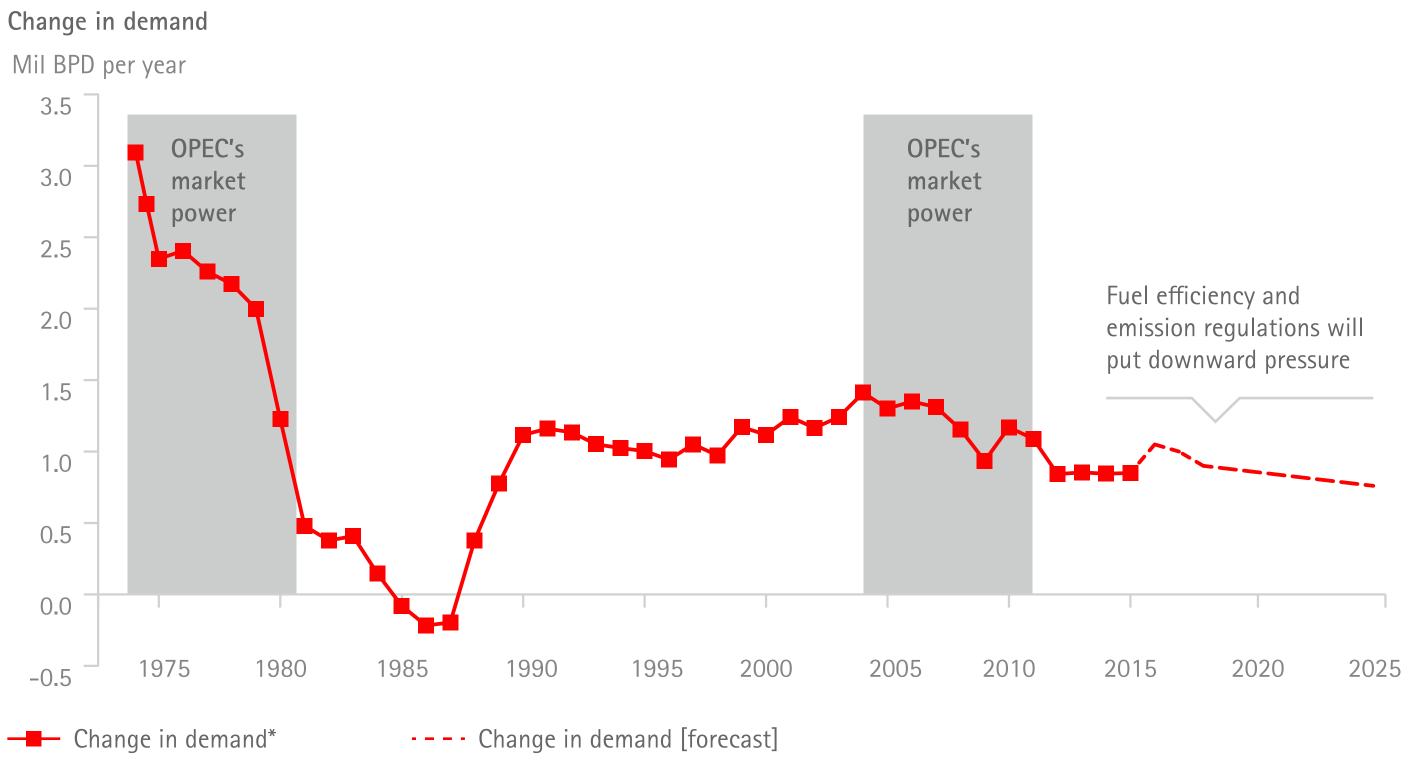
Source: Accenture Strategy, Energy analysis

Muted demand response

But oversupply is just half the story. For nearly three decades, demand growth for crude oil has been a hotly debated topic. After demand growth dropped sharply in the late 1970s through mid-1980s, it largely stabilized at around 1 million bpd/year. However, starting in 2003 demand growth began to decelerate: A five-to seven-year moving average puts the number closer to 0.7 million to 0.8 mil bpd/year (Figure 5).

Several factors underpin this downward bias. The first is a change in demand in the transportation sector, which is responsible for the vast majority of crude oil demand. Transportation providers' fuel consumption has declined as several OECD countries have increased fuel efficiency mandates and as providers themselves have replaced a portion of their traditional fleets with natural gas-or battery-powered vehicles. Now, the increase in energy efficiency has spread to non-OECD countries as well. In fact, the automotive industry has found that demand for fuel-efficient vehicles is just as strong, if not stronger, in non-OECD countries.

Figure 5: Crude oil demand growth has been range bound (moving average)

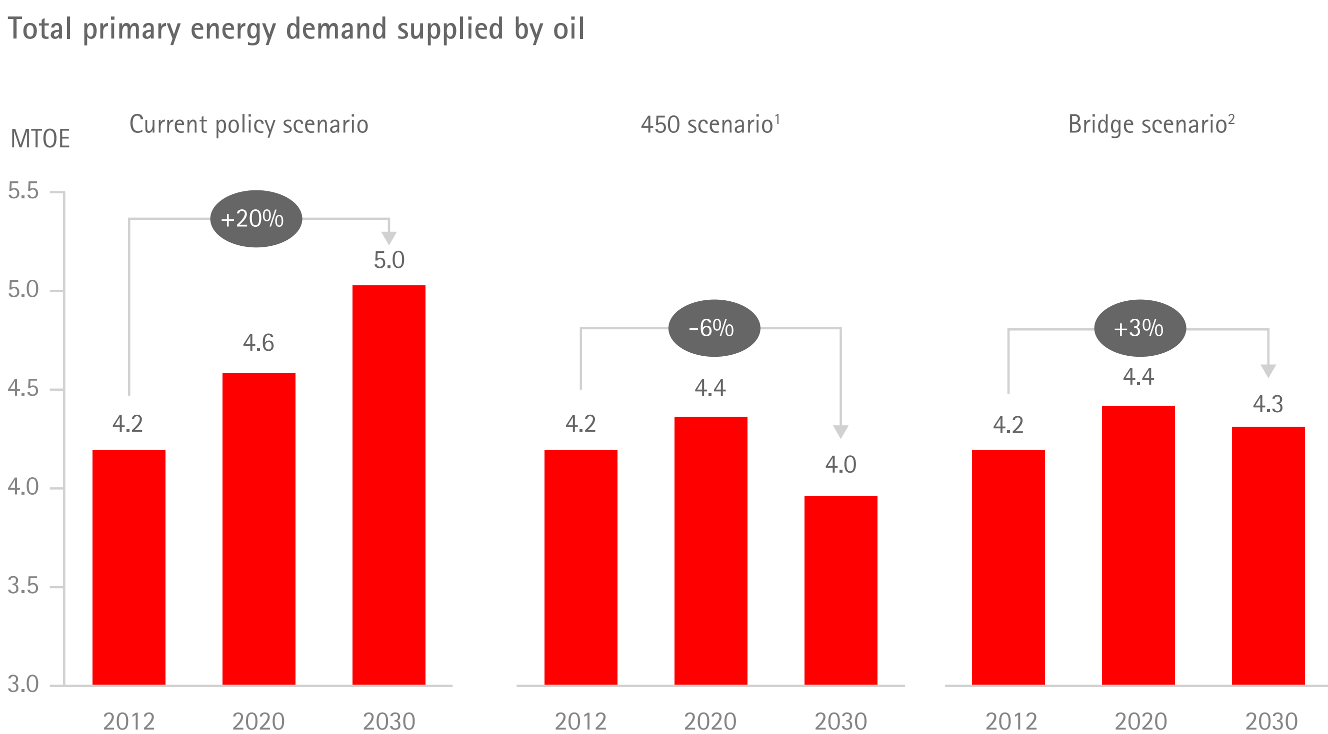


* 8-year moving average

Source: BP statistical review, Accenture Strategy, Energy analysis

Emission regulations also are dampening demand growth. Most developed and developing countries around the world agree that carbon dioxide emissions must be curtailed and regulated carefully to prevent global warming. Any such regulations will have a definite impact on crude oil consumption (Figure 6). As illustrated, achieving the 450 scenario will require a clear reduction in demand. But even in the bridge scenario, demand will fall.

Figure 6: Environmental regulations have downward impact on crude oil demand



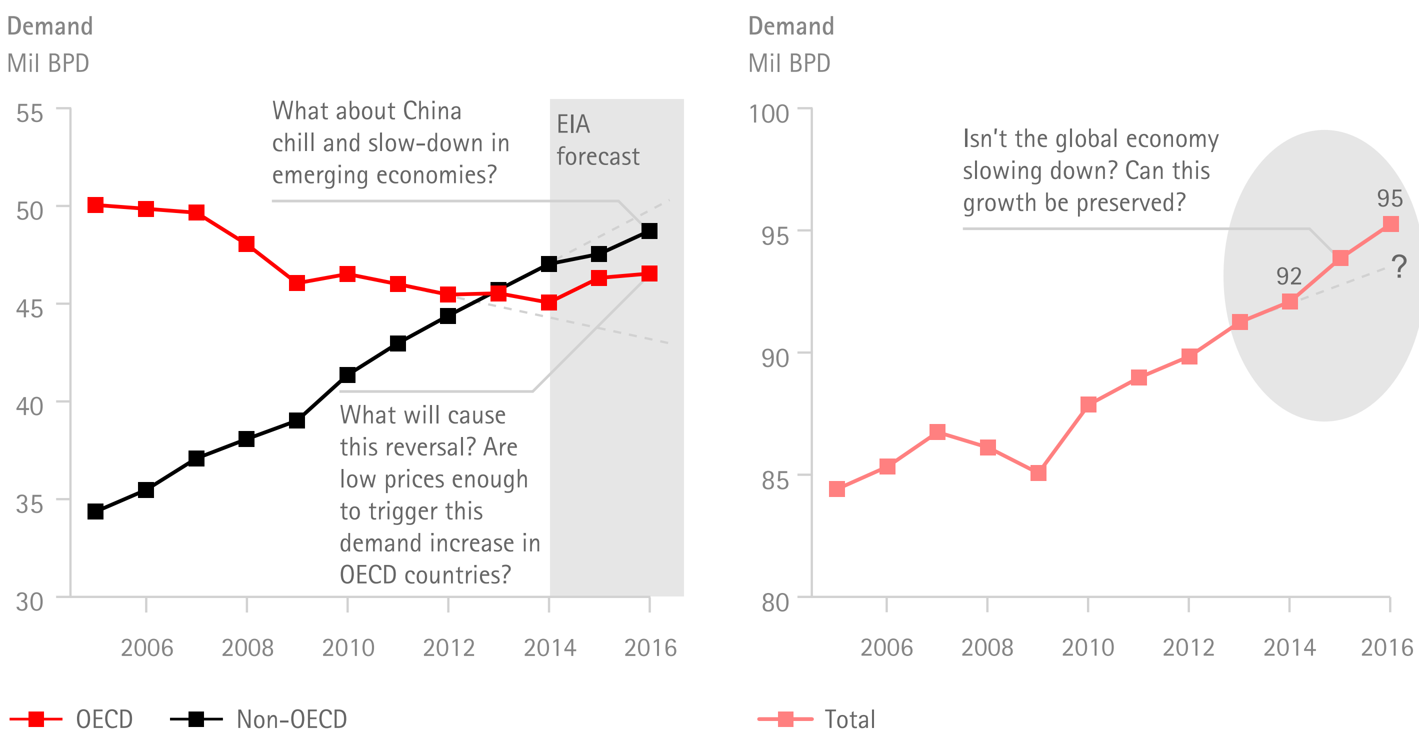
[1] A scenario that provides a 50% chance of constraining long term average global temperature increase to 2° Celsius

[2] A scenario that IEA proposed to deliver a peak in global energy-related emissions by 2020 as a response to COP21

Source: IEA

The fuel efficiency and emission stories combined lead to an inescapable conclusion: The secular reduction in crude oil demand from OECD countries will continue unabated, in contrast with the uptick EIA assumes. In addition, demand in non-OECD countries, which has now surpassed OECD demand, will likely slow—for two reasons: declining economic growth in countries like China, Brazil and India and increased fuel efficiency and emission regulations in non-OECD countries. When considering the net impact of these two factors, we believe demand growth will likely slow to 0.5 million bpd/year in the foreseeable future (Figure 7).

Figure 7: Slowing demand growth



Source: BP statistical review, EIA

Structural shift 2

Rapid, short-term movements in price

Watch out for choppy waters ahead.

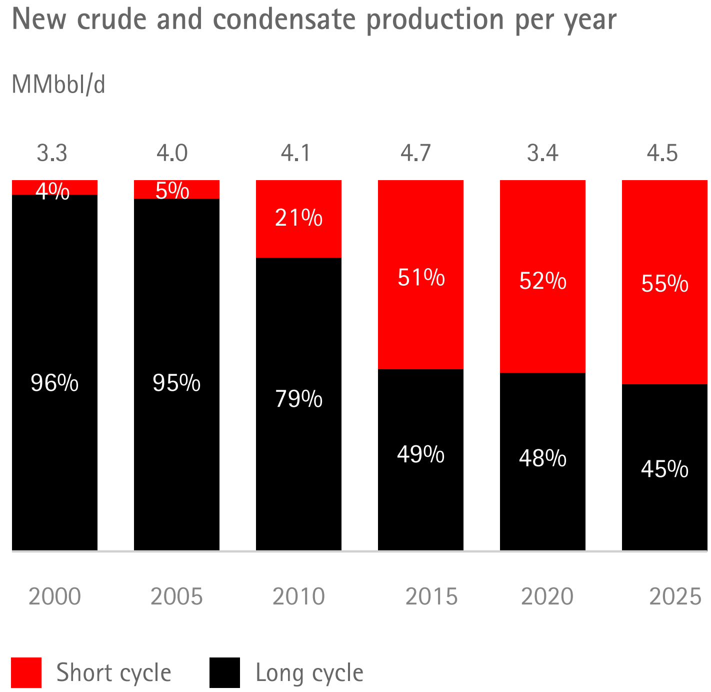
The industry is fixated on the absolute price point and a potential recovery timeline. But that longer-term perspective could obscure the emerging undercurrents of excessive short-term volatility that can wreak havoc on the operational plans of players of all size, geographical positioning and asset class focus for the foreseeable future. Three main factors are driving this enhanced volatility:

1. Supply uncertainty caused by:

a) Quicker "switchability" due to increasing contribution from short-cycle investments

A prominent shift in the supply mix has been the rapidly increasing contribution of production from short-cycle assets—primarily tight oil in North America, selectively onshore conventional and shallow water in mature geographies, and going forward, unconventionals in the rest of the world. As shown in Figure 8, nearly half of the incremental supply now comes from such assets. This provides both a reason for and response to volatility. Because investments can be quickly made and cut back, production spikes and drops would become more common; and, in fact, dealing with such fluctuation would require more optionality that these dynamic investments offer relative to those that are long-term in nature and consequently more rigid.

Figure 8: Yearly liquids supply mix between short cycle and long cycle sources[1]



Source: Accenture Strategy, Energy analysis

[1] Short cycle includes sources have development period of less than 1 year; the rest of the sources are defined as long term.

b) Lack of coordination across producers as a dominant cartel (OPEC) has made way to a number of disparate players with relevant supply contributions across the world

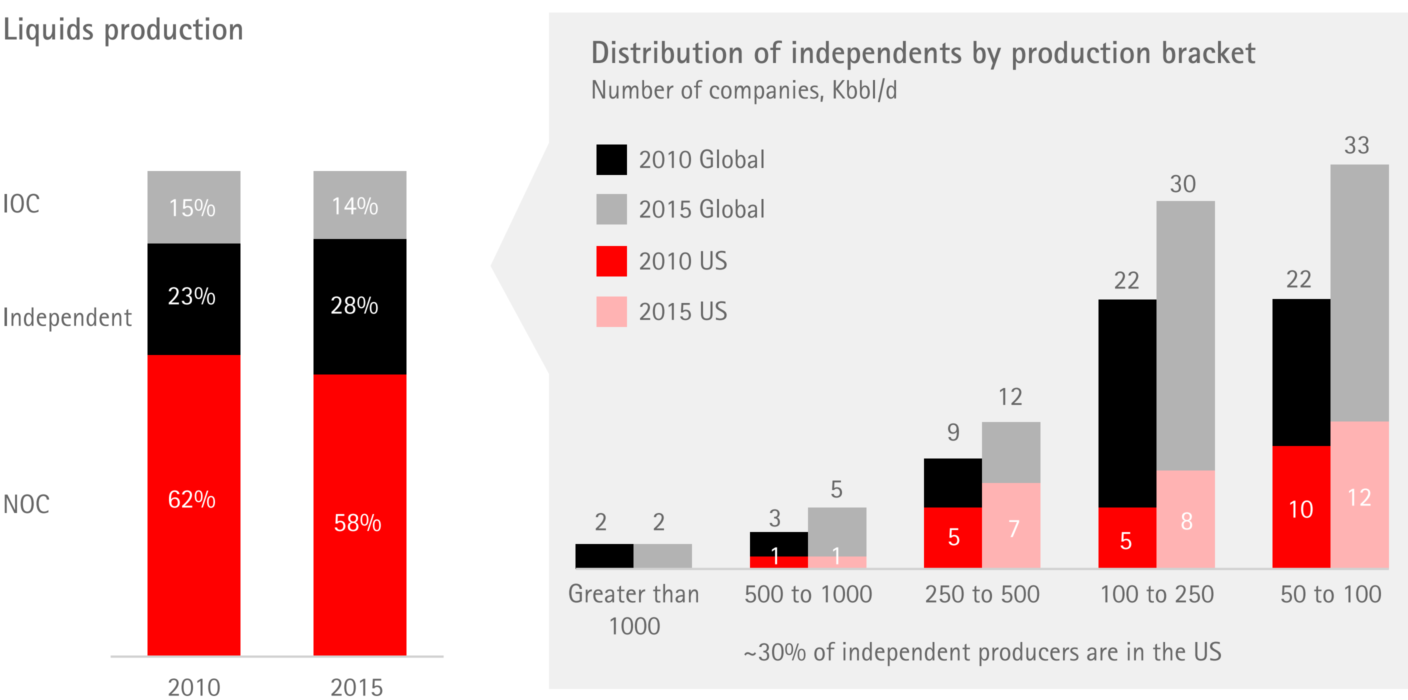
It's no hidden secret that OPEC's power as a moderating force in the oil and gas world has waned, though not entirely dissipated. This has coincided with a rise in production of certain non-OPEC countries (in particular, the US) as well as the number of productive operators globally. The latter is becoming especially more pronounced (Figure 9).

As a result of this shift, there are, and will be, more disparate actors playing their own tune—optimizing their individual timing, operating plans and performance metrics. This lack of synchronization would make managing emerging imbalances difficult and, in fact, exacerbate them on both the short and long ends, further adding to the volatility.

c) And overlapping economics across asset classes translating into multiple sources of marginal production in various price bands

The oil and gas industry has never been known for a perfectly rational and fundamentals-driven approach to supply. There are simply too many players, geographies, asset classes, and geopolitical interests involved to limit an economics-based allocation of production. However, in the past five years, the plethora of technically feasible supply sources has increased by an order of magnitude. More importantly, the band of feasibility for the various geographies and asset classes has widened, with considerable overlap. For example, deepwater production in parts of Brazil can be viable at $50/barrel, while that in West Africa may not break-even at $70/barrel. Similarly, in North America, intra-basin break-even estimates can range from $35 to $60/barrel, not to mention variation across major plays.

Figure 9: Production is becoming more segmented[2]



Note: IOC includes the 7 majors; NOC includes both "traditional" NOCs and NOCs with international assets; other includes refinery gains and other liquids

Source: Rystad, Accenture Strategy, Energy analysis

[2] There were 540 Independent Producers with production between 1 and 50 kbbl/d globally in 2015, 422 of which were in the US.

This is reflected in the supply curve (Figure 10), where large blocks of supply by source overlap. Complicating matters, operators in some cases may not have full visibility on the landing point for the economics of their developments until fairly late in the game.

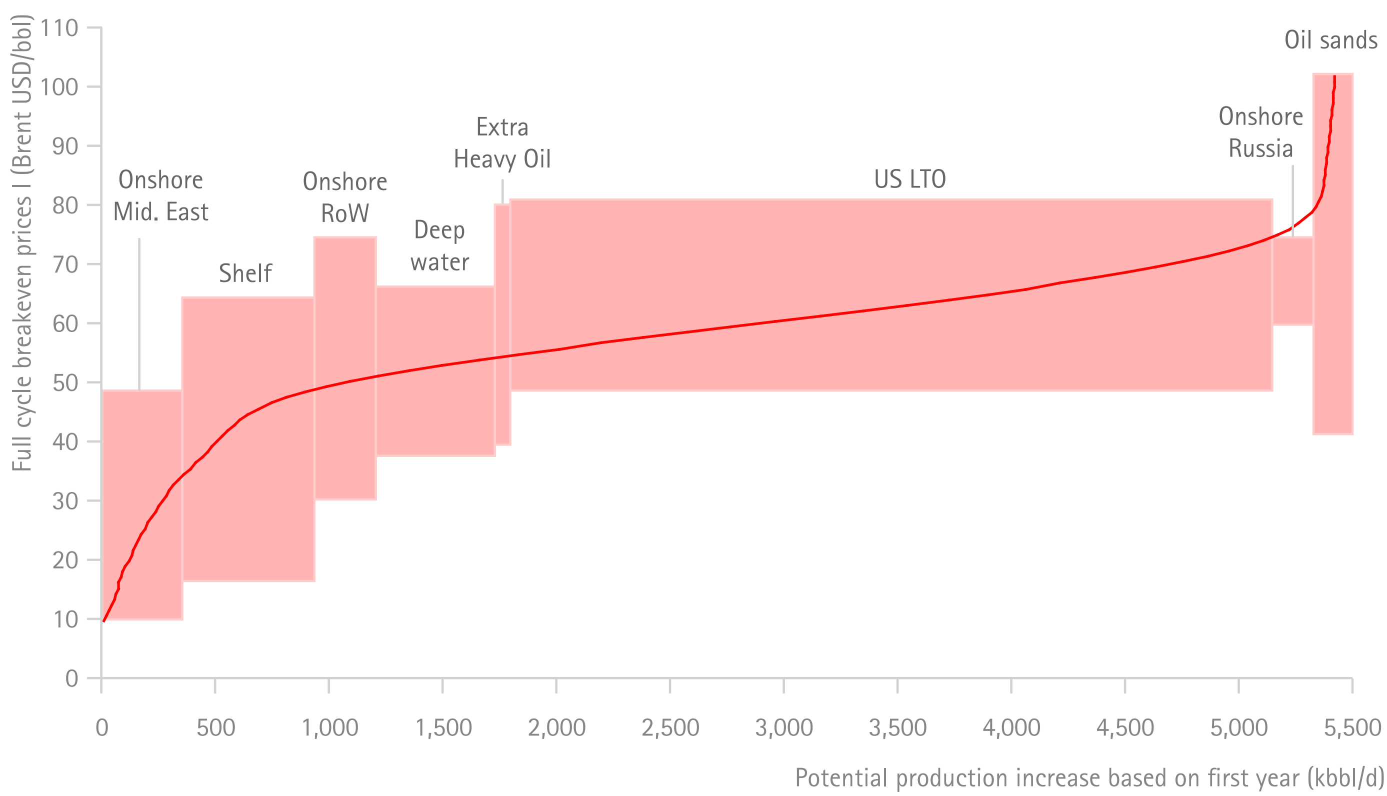
As a result, at various price trigger points, several different assets classes and geographies may be activated (or deactivated) by operators and governments—again overshooting (or undershooting) the required production levels to achieve balance. Looking ahead, this picture may only get muddier as even more sources come into play (including Iran, unconventionals in the rest of the world, and Russia offshore) and the future direction of the economics varies erratically across the varying supply types, driving further volatility.

2. Demand volatility caused by uncertain global economic outlook, particularly in countries that have recently accounted for the highest demand growth

The global economy exited a financial crisis almost six years ago and OECD countries' central banks are initiating changes to monetary policy that will likely impact economic growth. While the US seems to have recovered fully, several European countries still grapple with high levels of unemployment and poor economic growth rates. In non-OECD countries, which now account for the bulk of the oil demand increase, uncertainty reigns supreme. China's GDP grew only 6.9 percent in 2015, the lowest in 25 years. The ripple effects have riled not only the global commodity markets but also equity markets, as worries persist over a further slowdown in the Chinese economy and the resulting fallout it would bring.

Figure 10: Forward looking incremental supply curve

Simplified supply curve
2015 to 2025



Source: Accenture Strategy, Energy analysis

Russia and Brazil are in far worse shape, as both are squarely in recession. And several oil and gas-producing MENA countries are suffering a double blow: Recent civil wars have ravaged their infrastructure and society while low oil prices are seriously disrupting their economies.

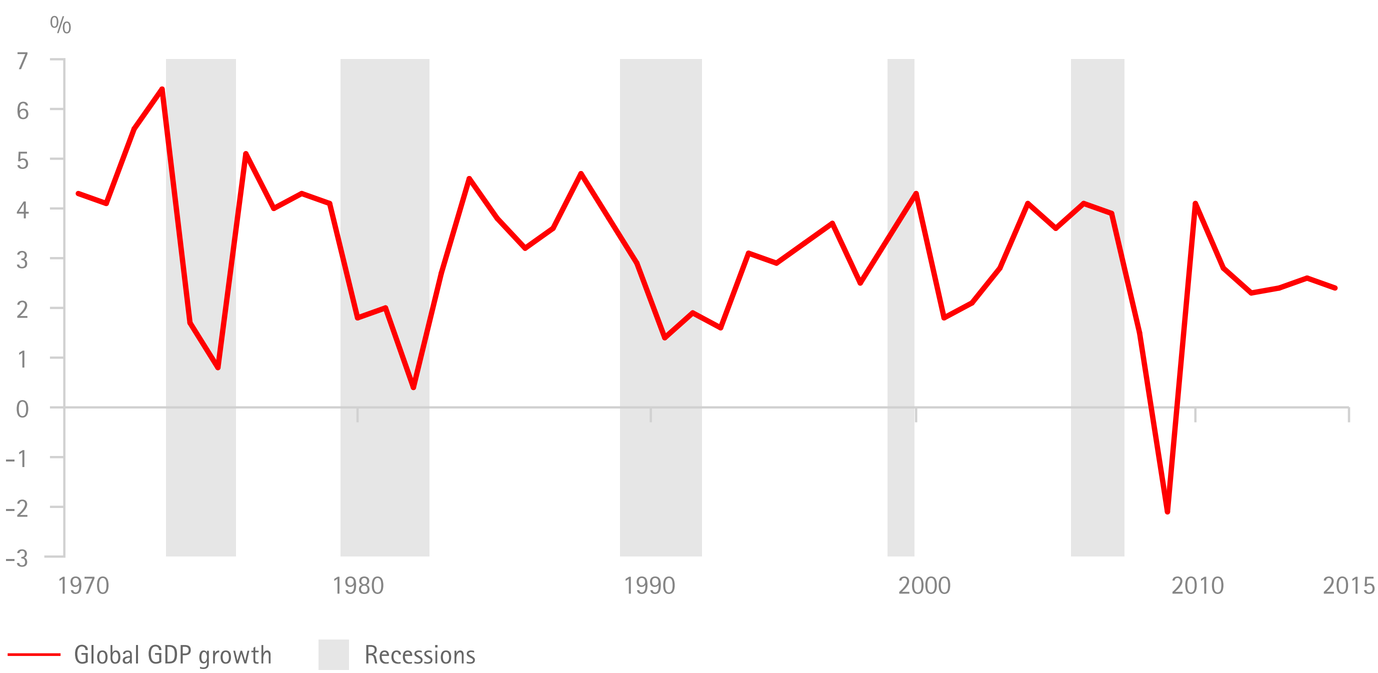
If history is any guide, we may be entering another period of recession (Figure 11). The specter of potential bankruptcies of Greece and/or Portugal is not helping the cause. The next crisis could happen in the next couple of years, adding instability to global crude oil demand.

And then there are carbon emission regulations. The latest agreements from the Paris Conference of Parties seem to impose less downward pressure on crude demand than the previous 450 scenario. But the very fact that these regulations are a moving target, and the terms and conditions change every few years, introduces an additional layer of uncertainty in crude demand.

3. A less pronounced and relatively less agile supply-demand balancing mechanism due to swing capacity in the form of LTOs instead of OPEC

The imbalance we see developing in commodity markets is mostly to be expected. Crude oil is necessary for modern economies to function. But finding and developing the exact amount needed, no more or less, is unlikely. Thus, in a market that is expected to be in flux, the role of a swing producer can be critical—a moderator of sorts that can help narrow or close imbalances and maintain a check on prices. OPEC, and its foremost player Saudi Arabia, had served in that capacity until recently. That role seems to have diminished or become mostly irrelevant (Figure 12) by a combination of factors—primarily OPEC's desire to maintain market share at any price and the increasing significance of North America tight oil in the supply mix, the production of which can be cranked up or down on short notice.

Figure 11: Global economic growth history



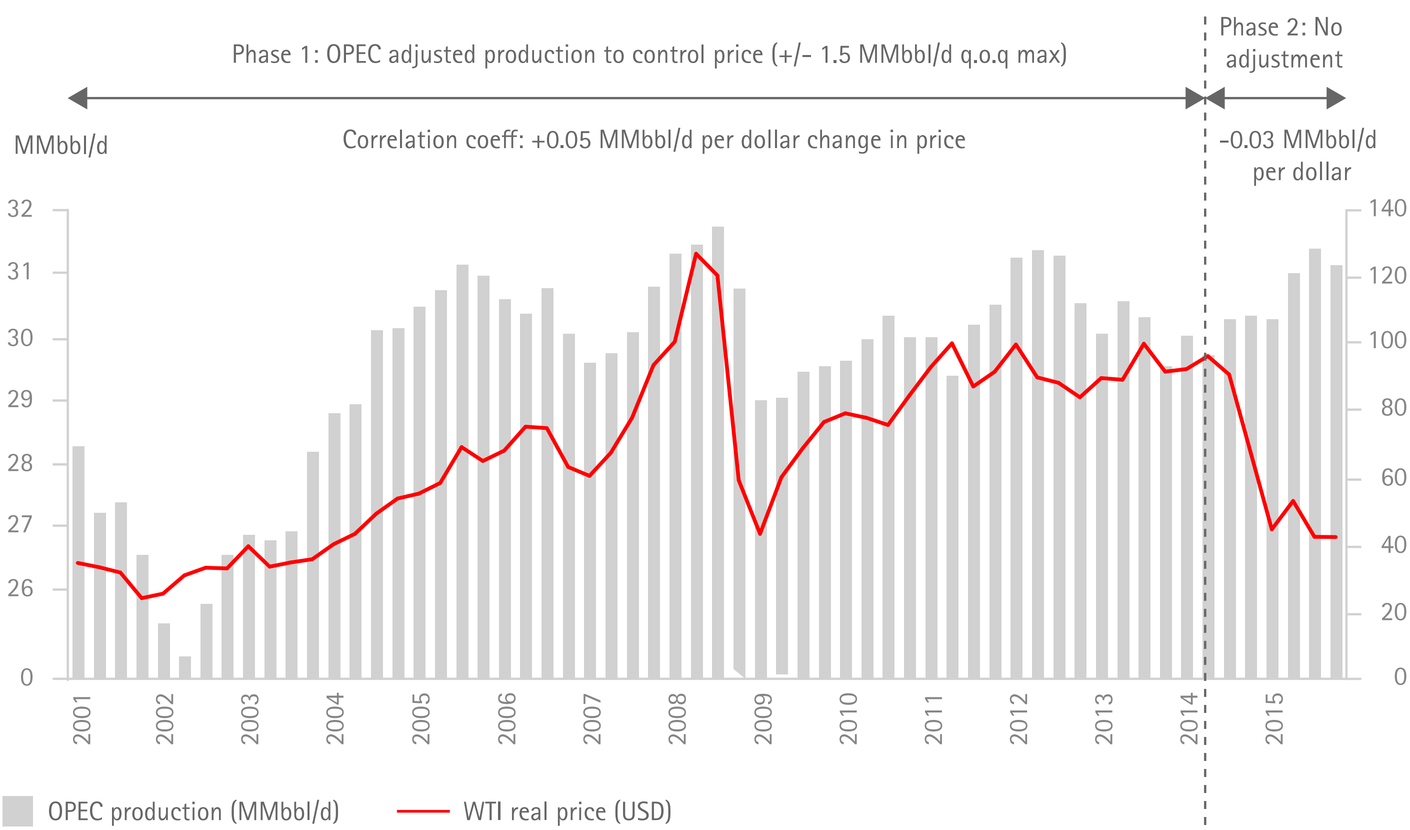
Source: World Bank, Accenture Strategy, Energy analysis

The former is manifested in historically low spare OPEC capacity (Figure 13). This has incidentally happened while there is a supply glut in the market; the excessive volume being pumped by OPEC by running down its spare capacity has exacerbated the imbalance.

The latter has made the US a swing producer—which, in itself, presents two challenges (Figure 14). One, although tight oil production can be ramped up and down quickly relative to most supply sources, it can't match OPEC's speed to market with its spare capacity. Two, because the US is, in effect, an amalgamation of dozens of disparate, independent swing producers, they can't act in unison like OPEC. Thus, any response by the US will be slower and less precise, which implies that imbalances will take longer to clear and generally will be overcorrected—which, in turn, worsens the system-wide short-term volatility within the long-term price band.

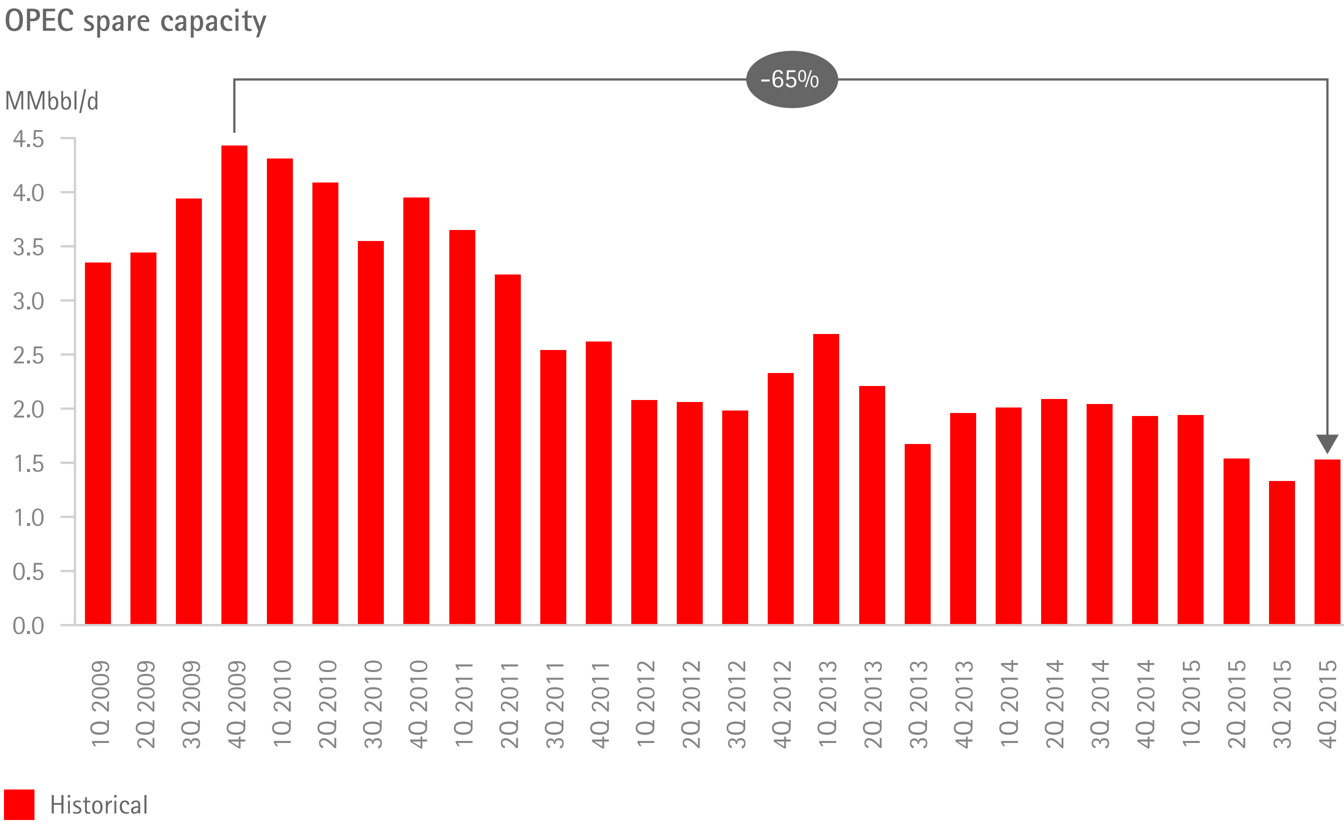
Figure 12: OPEC does not adjust production to oil prices

OPEC production and WTI crude oil prices



Source: EIA

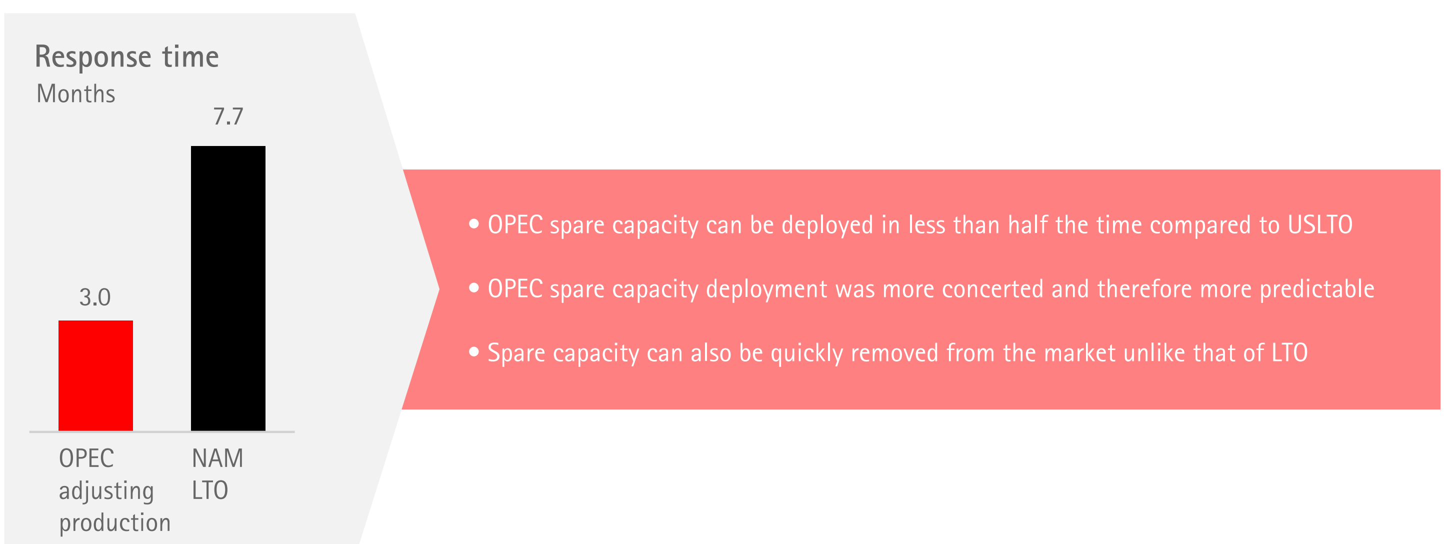
Figure 13: OPEC spare capacity declining



Source: EIA

Figure 14: Comparison of production adjustment time between OPEC and LTO

Average production adjustment time by source
Months, selected areas



Source: Rystad, Accenture Strategy, Energy analysis

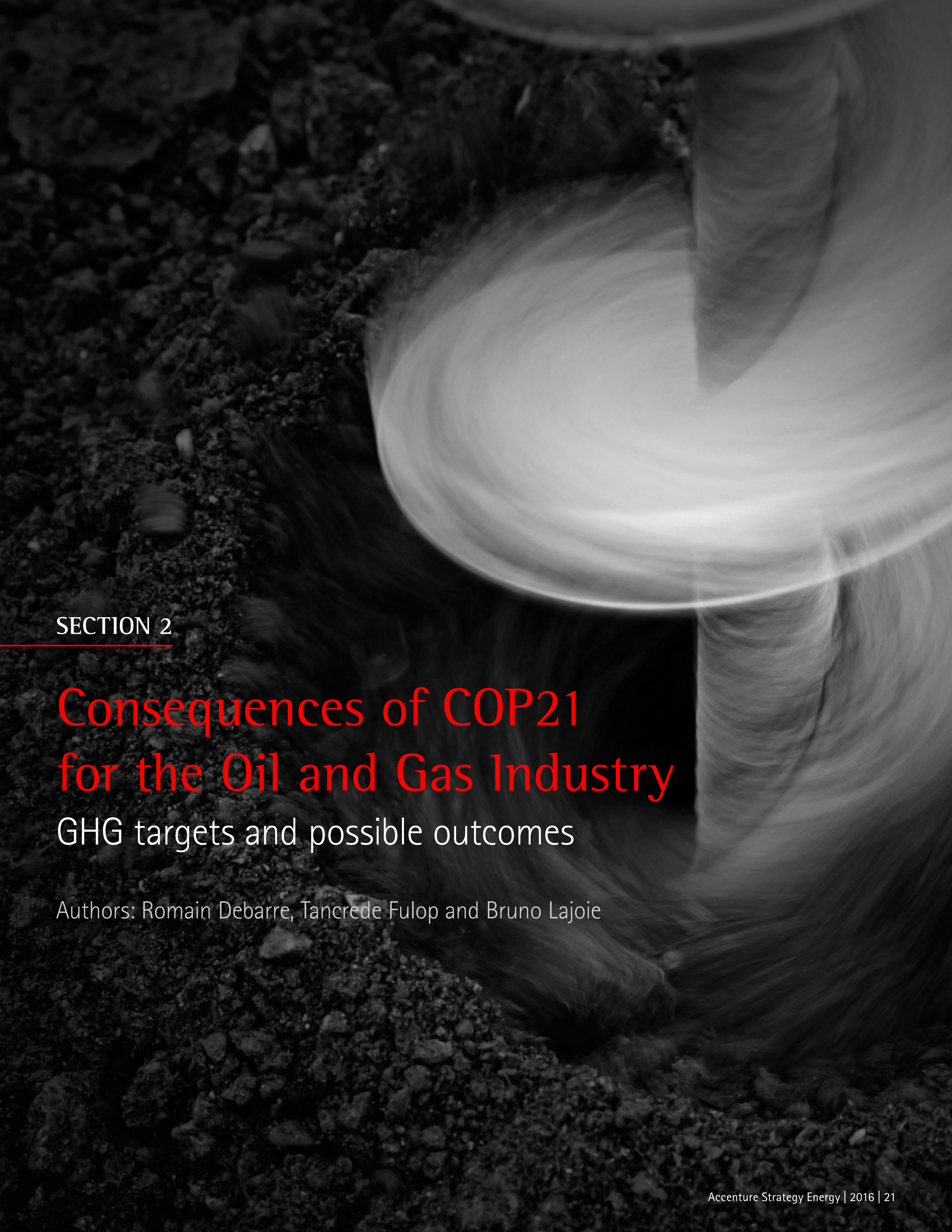
Preparing for a structurally lower and incessantly volatile oil price world

The structural disruption of the oil price curve caused by the unleashing of new supply sources, in particular unconventionals and deepwater, is here to stay.

This means the response from the industry must be commensurately transformative, as short-term adjustments will only help so much. Indeed, the vitality of the industry rests on a fundamental revamp, spanning the entire value chain, to counter the lower-price, volatile future we face.

What does this mean? It means portfolio and commercial models will have to evolve from being relatively rigid to being dynamic—evaluated with a finer resolution and with an eye to relevant performance measures. Siloed and arms-length relationships will need to make way for a collaborative internal and external ecosystem geared to respond nimbly and in a way that benefits all participants. And operating models and execution capabilities will have to be constructed not to reactively plug disparate gaps, but to proactively reshape how the company does business so it's positioned to thrive in this new future.

The world's best sailors don't wait until they're in the middle of tempest on the open sea to figure how to respond to turbulence. They thoroughly prepare their vessel, plans and crew before leaving port. That's something oil and gas companies should take to heart as they look to ready their own "ship" to encounter rougher seas ahead.



SECTION 2

Consequences of COP21 for the Oil and Gas Industry

GHG targets and possible outcomes

Authors: Romain Debarre, Tancrede Fulop and Bruno Lajoie

COP21

A historic agreement

After two decades of international negotiations (Figure 1), the 2015 United Nations Climate Change Conference in Paris (COP21) used a new "bottom-up" approach to successfully replace the Kyoto Protocol, thus setting the stage for future energy consumption. Including almost the entire international community, Parties agreed to "hold the increase in the global average temperature to well below 2°C above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5°C above pre-industrial levels" (Table 1).

Fulfilling that agreement will be a major challenge. Global warming by 2100 is expected to be roughly proportional to the cumulated greenhouse gas (GHG) emissions since the Industrial Revolution. Assuming that the proportion of CO_2 vs. non-CO_2 GHG emissions remains constant in the future (75 percent versus 25 percent in 2011), the Intergovernmental Panel on Climate Change (IPCC) estimates that the remaining carbon budget would need to be 1,000Gt CO_2 (Figure 2) to give the world a 66 percent chance of remaining below 2°C warming.

Table 1: Key COP21 articles

Article 2

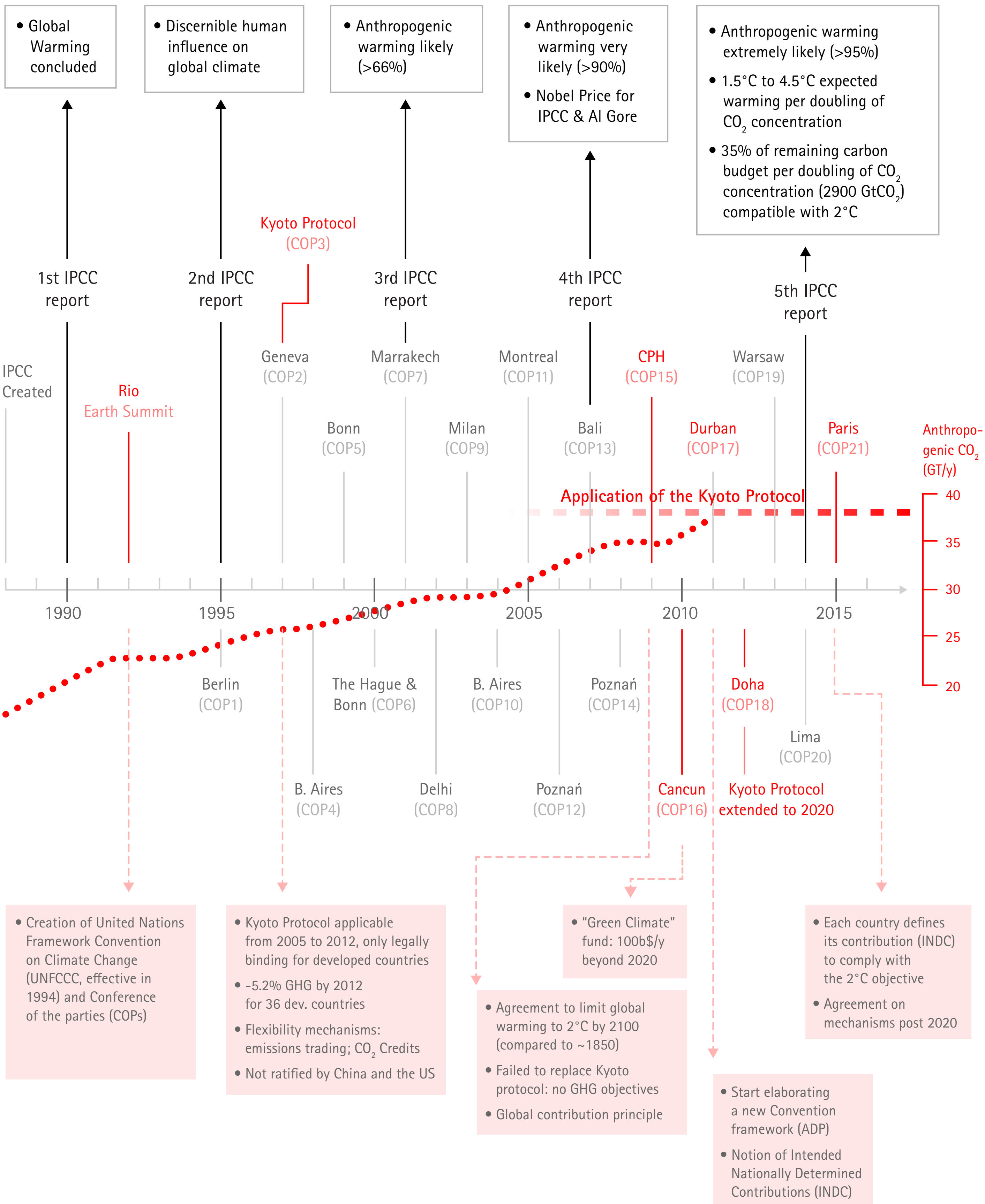
"This agreement aims to (...) holding the increase in the global average temperature to well below 2°C above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5°C above pre-industrial levels, recognizing that this would significantly reduce the risks and impacts of climate change;"

Article 4

"In order to achieve the long-term temperature goal set out in Article 2, Parties aim to reach global peaking of greenhouse gas emissions as soon as possible, recognizing that peaking will take longer for developing country Parties, and to undertake rapid reductions thereafter in accordance with best available science, so as to achieve a balance between anthropogenic emissions by sources and removals by sinks of greenhouse gases in the second half of this century, on the basis of equity, and in the context of sustainable development and efforts to eradicate poverty."

Source: United Nations—Framework Convention on Climate Change

Figure 1: Timeline of Conferences of Parties (COP) and IPCC reports

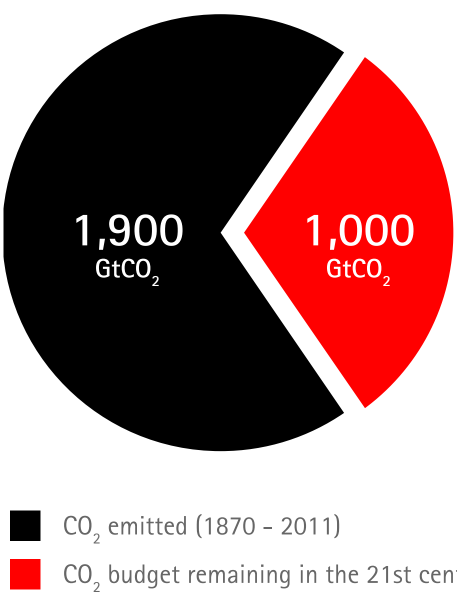


Source: Accenture Strategy analysis; UNFCCC; IPCC

Parties also committed to follow a transparent, progressive and powerful negotiation agenda—notably, providing non-binding fresh Intended Nationally Determined Contributions (INDCs) in 2020 and submitting revised binding INDCs in 2025, two years after the first global stocktake. This suggests pressure on the international community to limit GHG emissions will only increase.

As INDCs will be subject to redefinition and negotiation by Parties in the coming years, the fossil fuels consumption scenario beyond 2025 remains speculative. Nevertheless, it is acknowledged that the fossil fuels industry already has discovered more fossil fuels reserves than necessary to match the 1,000Gt of CO_2 budget (Figure 3). More precisely, no more than one-third of proven fossil fuels reserves can be consumed prior to 2050 if the world is to have a reasonable chance of achieving the 2°C goal, unless other carbon sinks (such as CCS, forestry and agriculture management) are widely deployed. Two key uncertainties remain: 1) how this carbon budget will be shared among countries and 2) in which proportion it will be distributed among fossil fuels. Indeed, the carbon intensity of various fossil fuels varies greatly: Coal is 30 percent more carbon intensive than oil and 70 percent more than gas. Thus, the remaining fossil fuel budget depends on the relative share of the three fuels consumed. Nevertheless, by 2035 the emission trajectory likely will converge toward the carbon budget of 1,000GtCO_2.

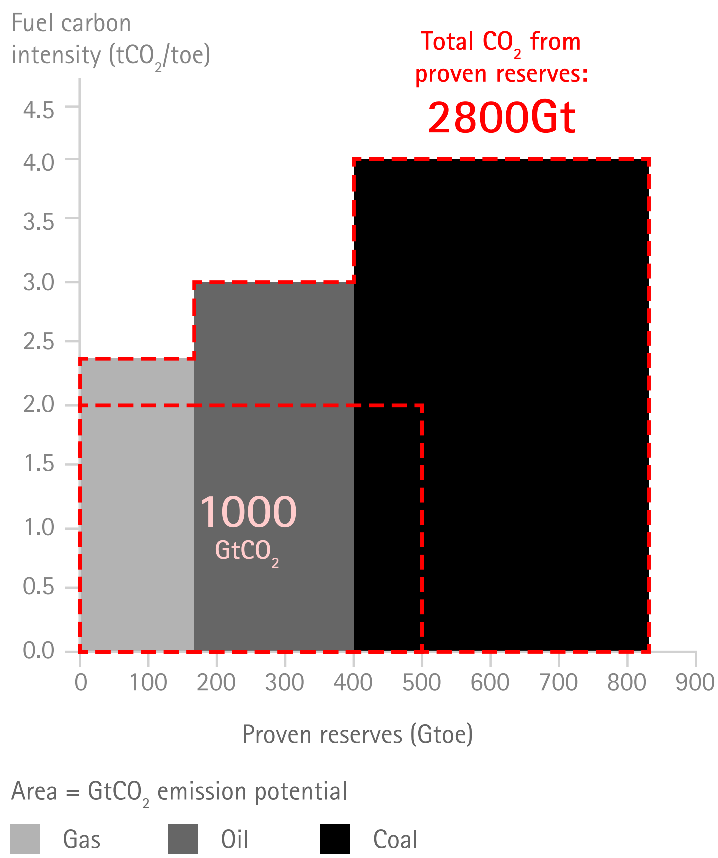
Figure 2: Carbon budget for the 2°C target



Carbon budget figures correspond to a 66% probability of limiting global warming below 2°C as per IPCC estimates.

Source: Accenture Strategy analysis; BP (2015) "Statistical review"

Figure 3: Fossil fuel proven reserves and carbon intensity



Source: Accenture Strategy analysis; BP (2015) "Statistical review"

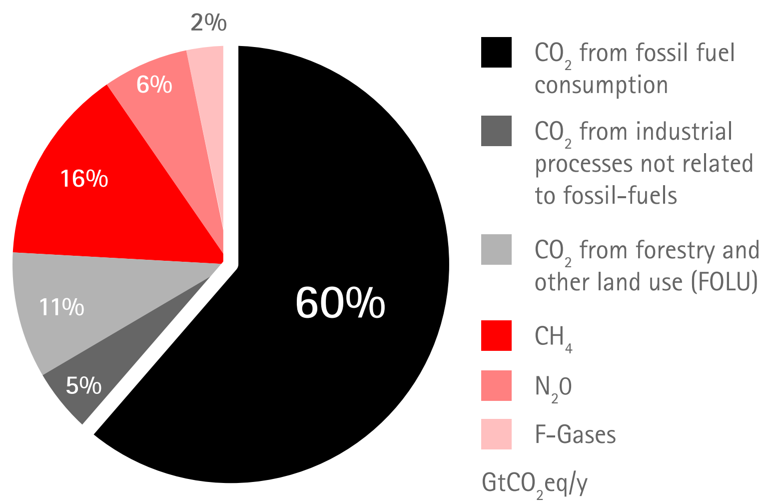
Forestry and agriculture management, as well as reduction of fugitive methane emissions, should play a major role in reducing GHG emissions. But as CO_2 emissions from fossil fuels represent 60 percent of the total GHG emission according to the IEA (Figure 4), the fossil fuels industry should make a significant contribution toward GHG reduction.

As illustrated in Figure 5, five main levers can reduce energy-related CO_2 emissions: 1) improving energy efficiency—i.e., consuming less for the same services; 2) developing renewable energies and 3) nuclear to substitute for fossil fuel energies; 4) capturing and storing CO_2 emissions; and 5) switching to less CO_2-intensive energies—e.g., from coal to gas.

It is not difficult to see the challenge the fossil fuels industry faces. In the past 40 years, the world has consistently increased its consumption of oil and natural gas at compound annual growth rates of 1 percent and 3 percent, respectively (Figure 6). Coal consumption has accelerated in the past 10 years at 4 percent per year. The recent Paris agreement no doubt will cause countries to significantly reduce global anthropogenic GHG emissions which, in turn, will have a major impact on the fossil fuels industry.

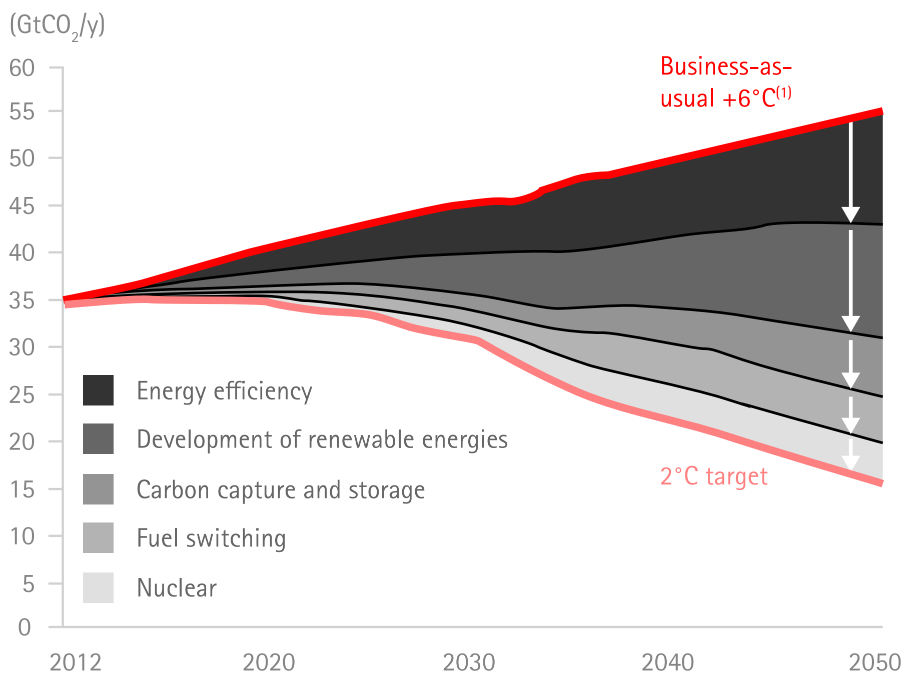
This article describes INDCs and strategies that some countries committed to follow to reduce anthropogenic GHG emissions, with a specific focus on fossil fuels. It also explores possible consequences for the oil and gas sector and immediate steps the industry could deploy to help mitigate global warming.

Figure 4: Distribution of the total annual anthropogenic GHG emissions in 2010



Source: IPCC (2014) "AR5, WGIII"

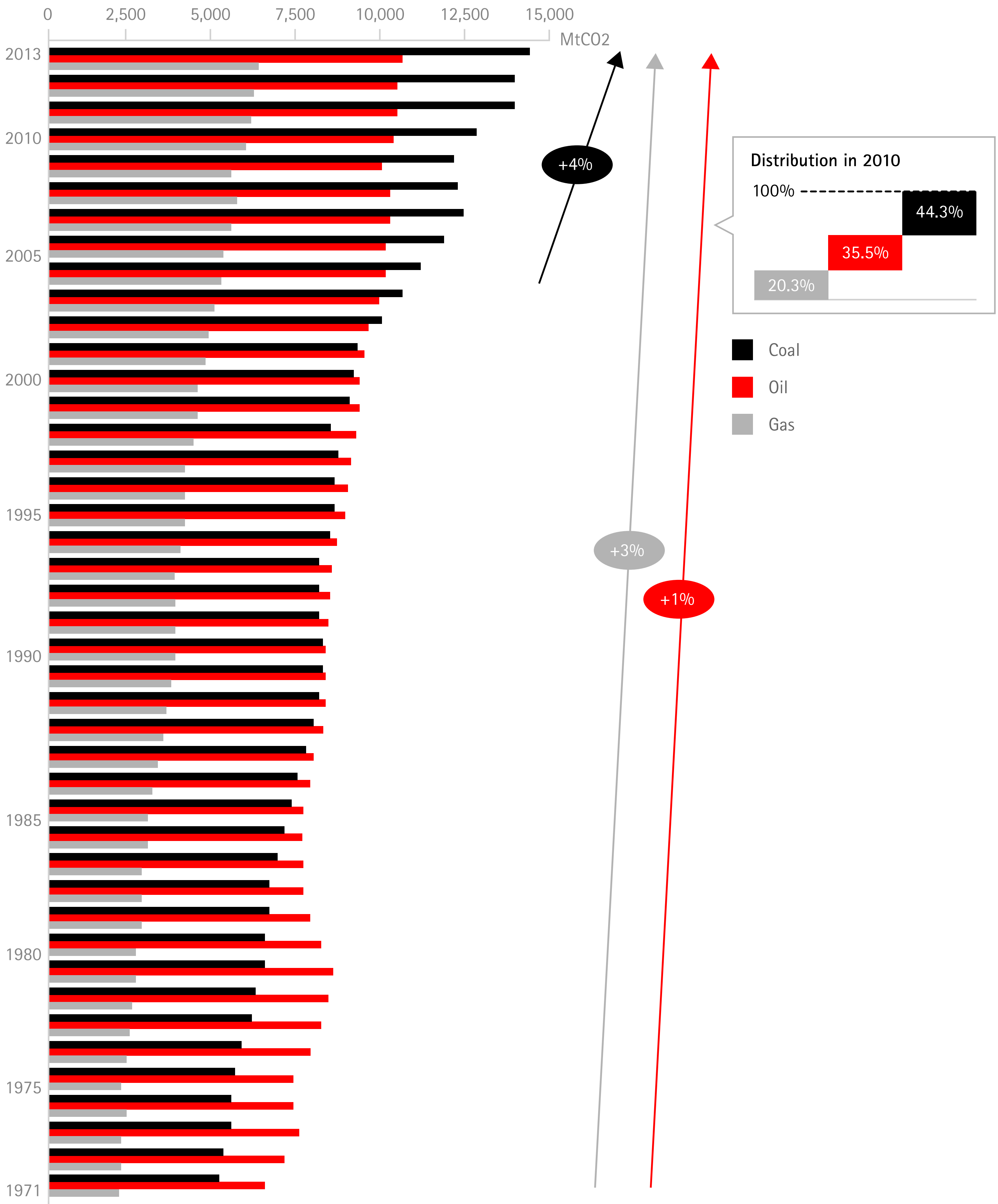
Figure 5: Fossil-fuel CO_2 reduction scenario



[1] "The 6DS assumes no GHG mitigation efforts beyond policy measures already implemented, which could lead to a 60% increase in annual energy- and process-related CO_2 emissions to a level of 56 gigatonnes of CO_2 ($GtCO_2$) and a potentially devastating global average long-term temperature increase of around 5.5°C." - IEA ETP 2015.

Source: modified from IEA, World Energy Outlook 2015

Figure 6: CO_2 emissions from fossil fuels consumption



Source: IEA, "CO_2 Emissions Highlight 2015"

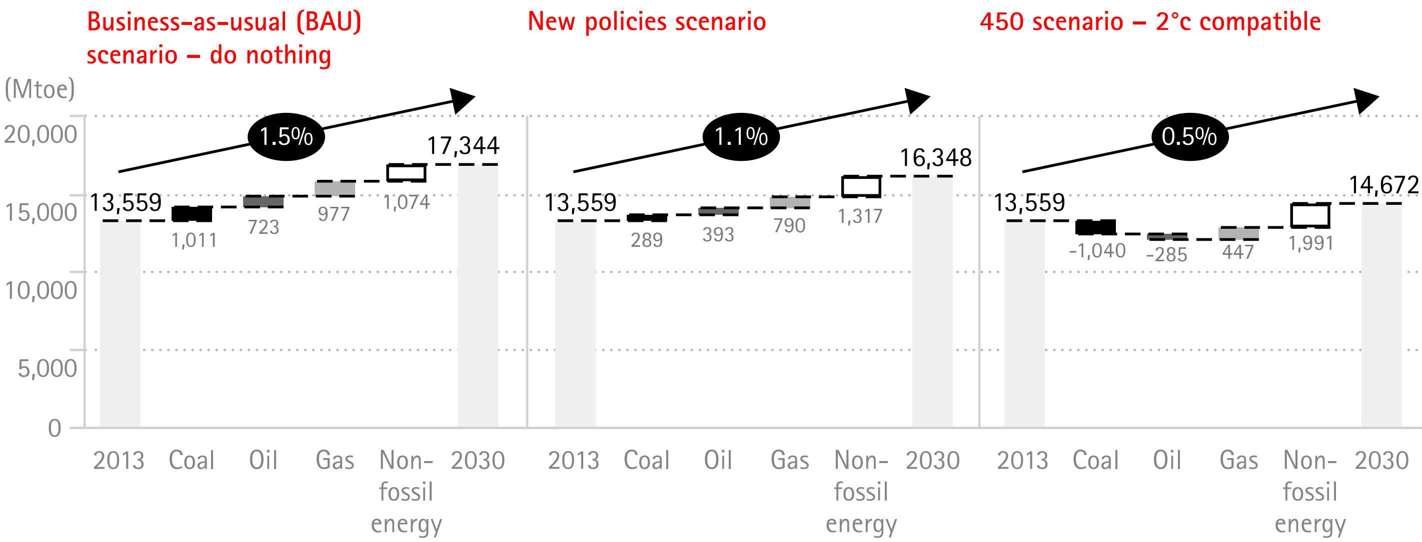
INDCs, GHG emissions target, and countries' strategies

A global commitment to adhere to a carbon budget that implies the deceleration of the fossil fuels industry's expansion

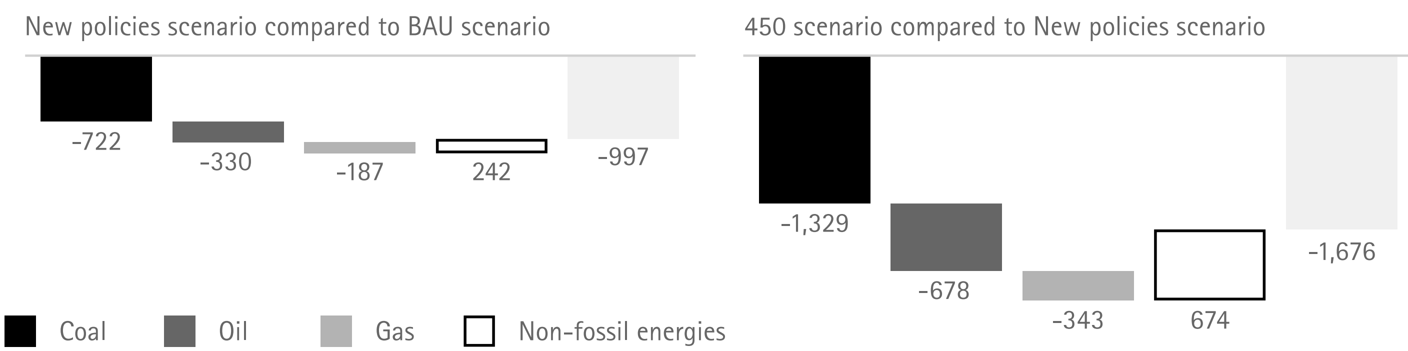
When signing the Paris agreement, Parties implicitly committed to collectively work within the remaining carbon budget estimated at 1,000Gt of CO_2, according to IPCC. But GHG emissions-reduction strategies vary across countries, and the evolution of the energy mix will take divergent paths in different regions. Similarly, INDCs' content is not equally shared among Parties, neither in their purposes nor in their intensity.

Nevertheless, the global CO_2 emission trend is set to reverse course, meaning the global energy mix should evolve toward less fossil fuels consumption. According to IEA's New Policies Scenario, pre-COP21 submitted INDCs already embedded a fossil fuel consumption reduction of 997 Mtoe compared with the business-as-usual scenario, which corresponds to slowing fossil fuels consumption growth by 25 percent compared with the previous trend (Figure 7). Fossil fuels consumption still has a positive CAGR of about 1 percent. But the 2°C target, associated with the 450 Scenario, will probably drive the fossil fuel economy toward a 0.5 percent CAGR, almost destroying all the potential growth of this economic sector. More precisely, if the New Policy Scenario maintained some growth potential for all three fossil fuels, the 450 scenario illustrates a clear consumption decrease for coal and oil but allows for a small increase for natural gas. The actual fossil fuels consumption scenario will most likely end up between the New Policy Scenario and the 450 Scenario.

Figure 7: Global energy consumption scenarios



Variation in fossil fuels consumption between scenarios over 2013-2030



Source: IEA, World Energy Outlook 2015

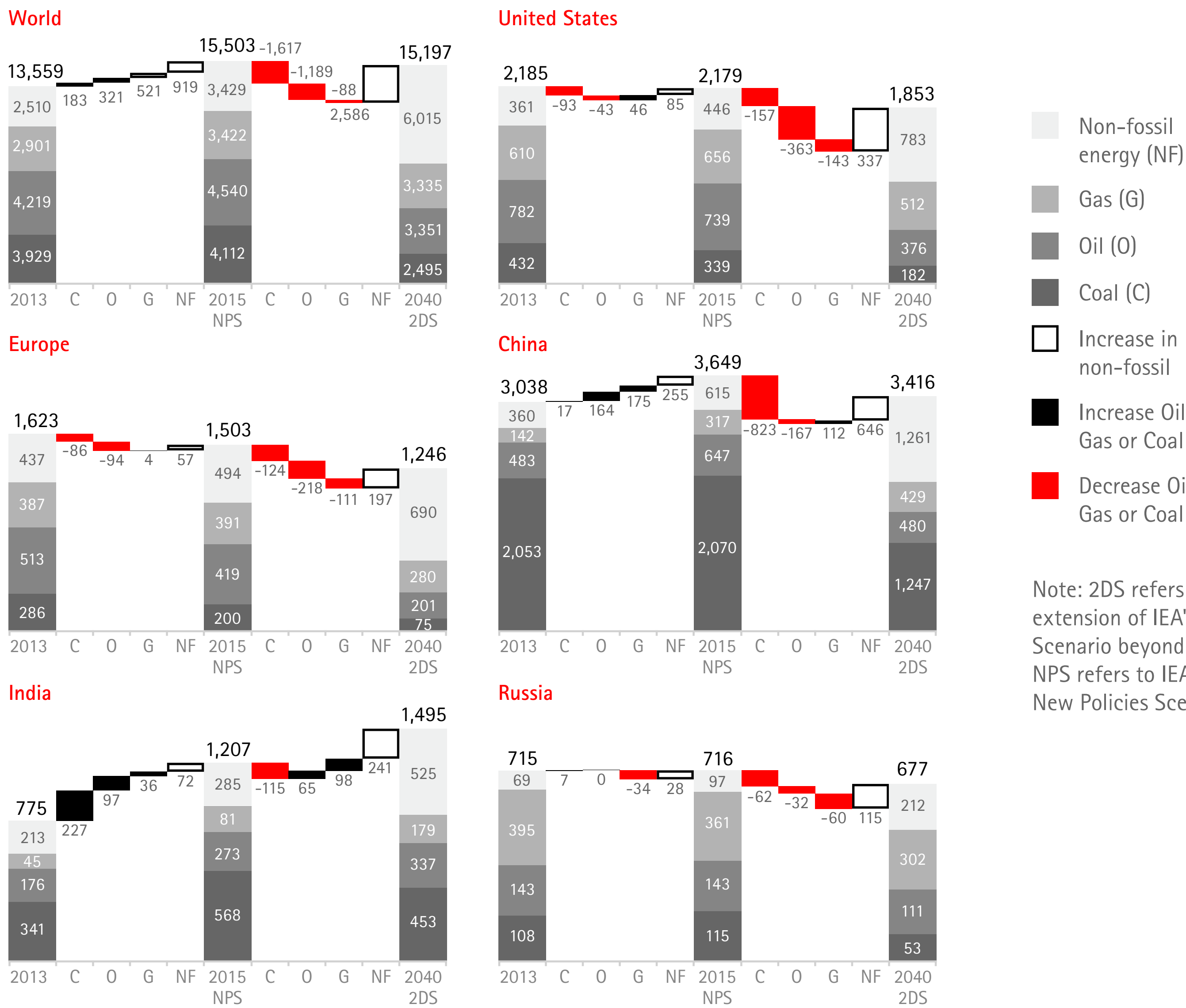
CO_2 emissions-reduction efforts will primarily affect coal, then oil, and finally gas

Some countries are already on the verge of reducing fossil fuels consumption. This is the case for Europe and the United States, which intend to reduce fossil fuels consumption, respectively, from 1,623 Mtoe in 2013 to 1,503 Mtoe in 2025, and from 2,185 Mtoe in 2013 to 2,179 Mtoe in 2025. Other countries—including China, India, and Russia—intend to either increase or stabilize their consumption in the same period. Lastly, almost all major consuming countries—except a few countries, notably India—plan to reduce fossil fuels consumption after 2025.

Reduction in fossil fuel consumption will primarily rely on coal, then oil and, in some countries, natural gas. Reduction in coal consumption is expected before 2025 in the United States and Europe, and globally beyond 2025. Similarly, oil consumption is expected to decline in the United States and Europe before 2025 while continuing to grow in China, India and Russia in the same period. Consumption should begin to decline after 2025 in China and Russia, but continue to grow in India.

Natural gas likely will be the beneficiary of coal's and oil's decline. As gas emits less CO_2 per unit of energy consumed than coal and oil, it should still be growing in such countries as China and India beyond 2025.

Figure 8: Breakdown and evolution of consumption per fuel type in 2013, in 2025 according to the New Policy Scenario and in 2040 according to the 2DS scenario, for the World and major consuming countries



Note: 2DS refers to the extension of IEA's 450 Scenario beyond 2035; NPS refers to IEA's New Policies Scenario

Source: IEA, "Energy Technology Perspective 2015"

Four main possible consequences for the oil and gas sector

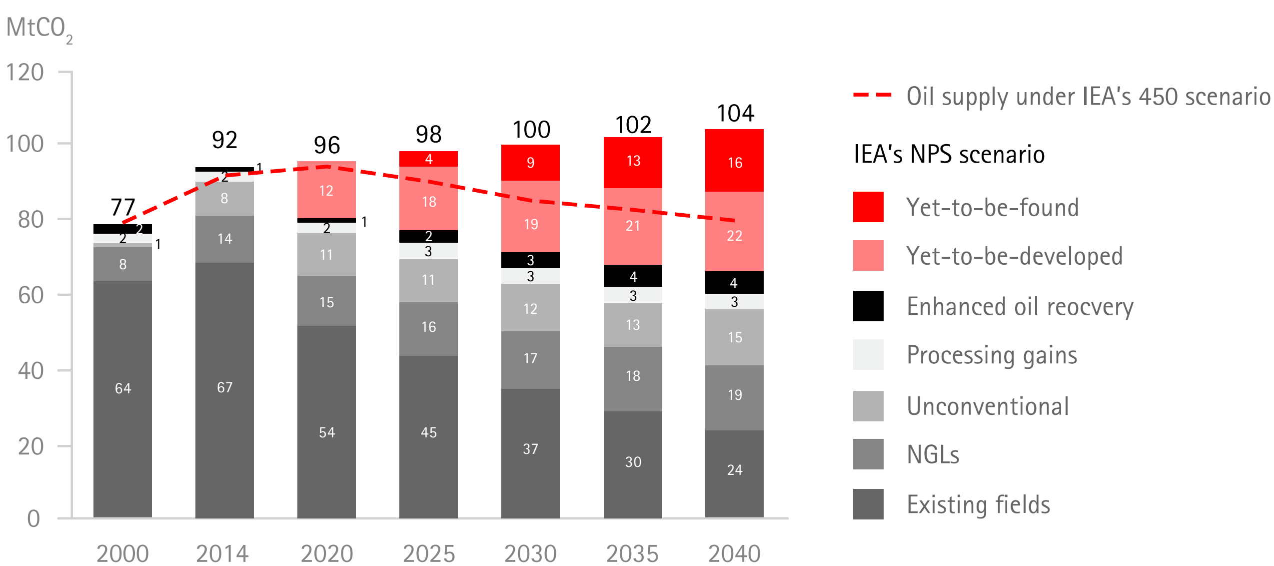
Under IEA's 450 scenario—which is consistent with capping global warming to 2°C—oil demand would peak in 2020 before decreasing to 74 mb/d in 2040, 30 mb/d lower than under IEA's New Policies scenario (Figure 9). As the New Policies scenario includes INDCs submitted by countries just before COP 21, one can consider it the new "business as usual." Future oil demand therefore will likely evolve between New Policies and 450, which we will call, respectively, high-demand and low-demand scenarios. In this regard, oil demand should fall somewhere between -0.9 percent a year (low demand) and +0.5 percent a year (high demand) between 2014 and 2040.

This evolution likely will affect the oil and gas industry in four important ways.

1. Exploration would eventually end

Much lower demand under a 2°C-compliant scenario would involve dramatic changes with regard to the origin of future oil production: In such low-demand scenario, only 13 percent of oil produced over 2020-2040 would come from yet-to-be-developed reserves (versus 27 percent in our high-demand scenario), and no production would come from future discoveries, meaning that exploration would end as the oil and gas industry has already discovered sufficient reserves to match its share of carbon budget and should not develop all its current discoveries. This tends to indicate that, depending on the outcome of future climate policies, exploration will be significantly reduced, but might continue in the short to medium term.

Figure 9: World oil supply and demand by type in IEA's New Policies scenario vs. 450 scenario (mb/d)



Source: IEA, "World Energy Outlook 2015"; Accenture Strategy, Energy analysis

2. Drastic cut of exploration and development should drive significant reduction in capex

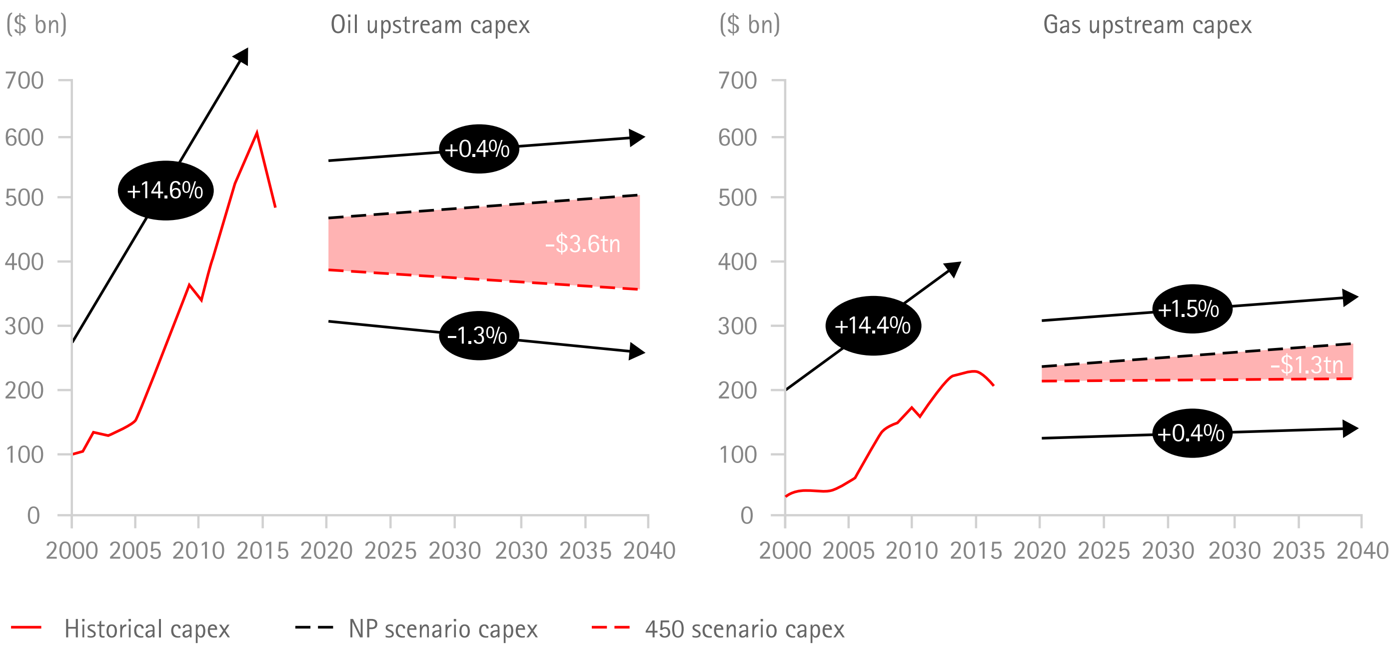
E&P companies' capex have been surging by 14 percent per annum between 2000 and 2014 (Figure 10), reflecting not only inflation in the industry, but also a growing share of deep-water and costly unconventional assets within reserves being discovered or developed.

In our high-demand scenario, upstream investment would amount to $19.5 trillion between 2015 and 2040—65 percent of which will be for oil and 35 percent for gas. That points to an average of approximately $775 billion per year, or $500 billion for oil and $275 billion for gas. In our low-demand scenario, capex would be 25 percent less, generating a $4.9 trillion savings during the same period, or $196 billion annually. We calculate a 29 percent discount for oil and 19 percent for gas capex, as the reduction in oil demand (-16 percent) would be larger than for gas (-11 percent) during that period.

For oil, slowing demand starting in 2020 could drive a 1.3 percent annual decline in capex versus a +0.4 percent increase under the New Policy scenario. For gas, capex would continue to increase until 2040 under both scenarios, in line with growing demand. The bottom line: the investment discount should range between 0 and 25 percent as illustrated by the pink areas in Figure 10.

As discussed, reduced investments would be driven by the cancellation of exploration and much lower development expenses. In turn, much lower investment, coupled with the fact that some E&P companies' reserves might never be developed, will upend the sector's economics and financial equation.

Figure 10: Evolution and forecasts of upstream oil & gas capex



Source: IEA; IHS; Accenture Strategy, Energy analysis

3. Many upstream assets would become stranded, with a higher proportion for gas than for oil

According to a 2015 model from McGlade and Ekins, a 1,000Gt cap on CO_2 emissions by 2050 implies that 33 percent of the world's oil, 50 percent of its gas, and 80 percent of its coal reserves would be stranded[1].

Depending on quantities, locations, and nature of the world's fossil resources, McGlade & Ekins assessed the breakdown of stranded assets by region. Under their assessment, a low share of fuel being exported and cheap low-polluted production would result in a low percentage of stranded assets, while low local consumption and expensive high-polluted production would increase the percentage of stranded assets.

Despite the fact that gas is cleaner than oil, the percentage of stranded assets is higher for the former as reserves are also relatively larger (55 years at the current consumption rate, versus 39 years for oil). The higher percentage of gas assets potentially stranded might be problematic for E&P companies willing to decarbonize their portfolio by switching from oil to gas.

4. Stranded assets could disproportionately affect producing countries

The Middle East, home to the largest reserves of oil and gas in the world, would account for the largest share of stranded assets. Indeed, 61 percent of stranded oil assets and half of stranded gas assets in the world would be in the Middle East. The percentage of the Middle East's oil reserves being stranded would amount to approximately 40 percent, according to McGlade & Ekins, allowing 60 percent of its reserves to be produced. On the other hand, 61 percent of the Middle East's gas reserves would be stranded by lack of local demand.

Russia would account for 32 percent of unburnable gas reserves in the world and half of its gas reserves would be stranded.

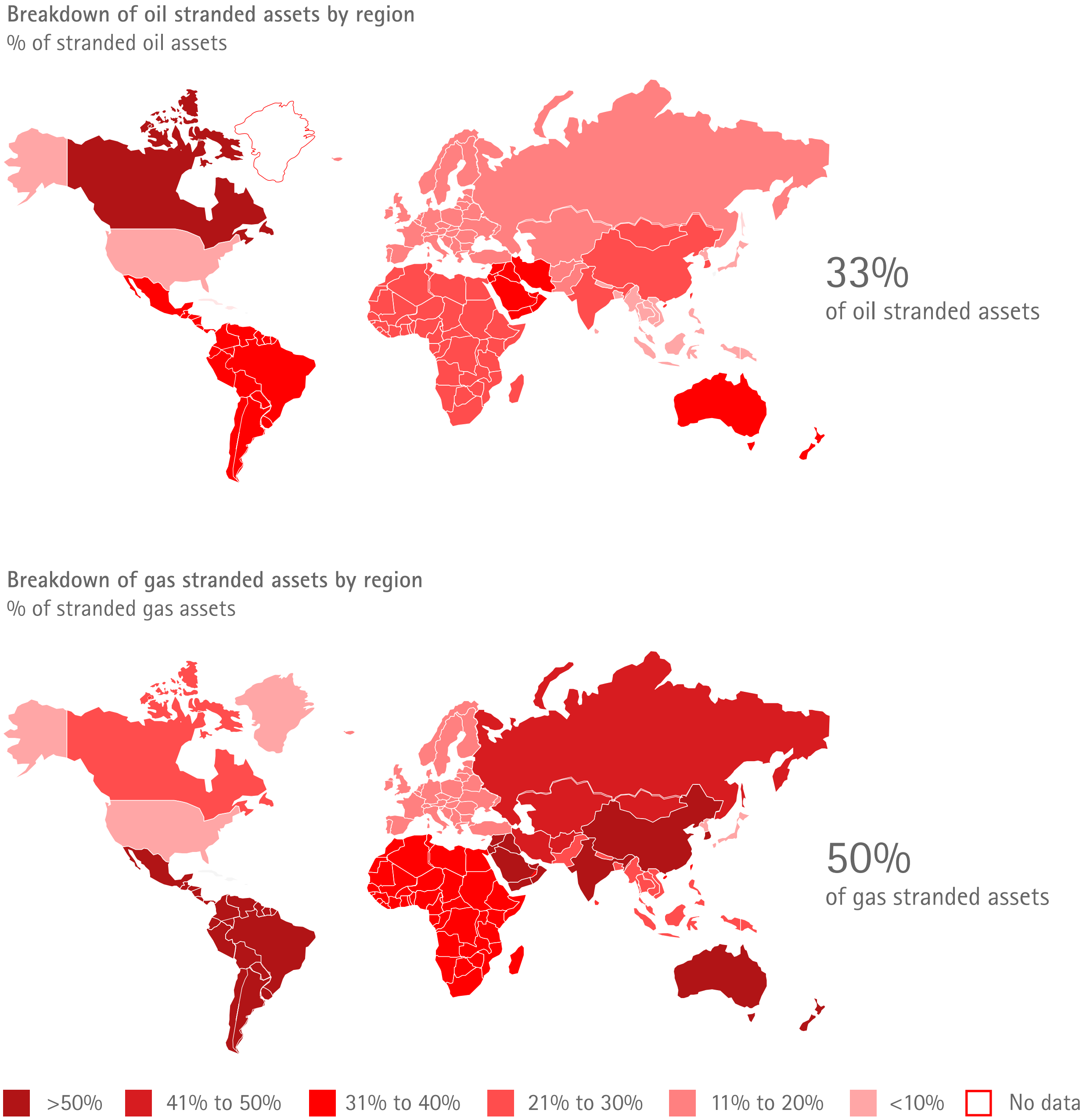
Canada would have the highest percentage of stranded oil reserves in the world at 74 percent, largely because highly polluting and expensive production of oil sands which predominate in Canada's oil reserves.

The US has the lowest percentage of stranded oil (6 percent) and gas (4 percent) assets, mainly because of the proximity of production to consumption. Indeed, the US could produce its reserves for its own consumption while reducing fuel imports.

The reality is that the regional distribution of stranded fossil reserves is a very sensitive topic. Indeed, according to a Nelson, et al. (2014) estimate in a Climate Policy Initiative (CPI), governments own 50 percent to 70 percent of global fossil fuels. And every country that signed the COP21 final agreement theoretically agrees to implement policies consistent with limiting global warming to 2°C, which may indirectly require those governments to not produce their stranded assets. However, one can imagine that governments will not easily relinquish their fossil-fuel reserves—whether it is because some economies, especially those in the Middle East, are simply too dependent on their fossil fuels and have yet to transform themselves to reduce this dependence; or because of the highly variable share of stranded assets across countries and regions.

[1] Stranded means that those reserves would be unburnable before 2050 under the 2°C-compliant scenario.

Figure 11: Breakdown of stranded oil & gas assets by region, percent of stranded assets



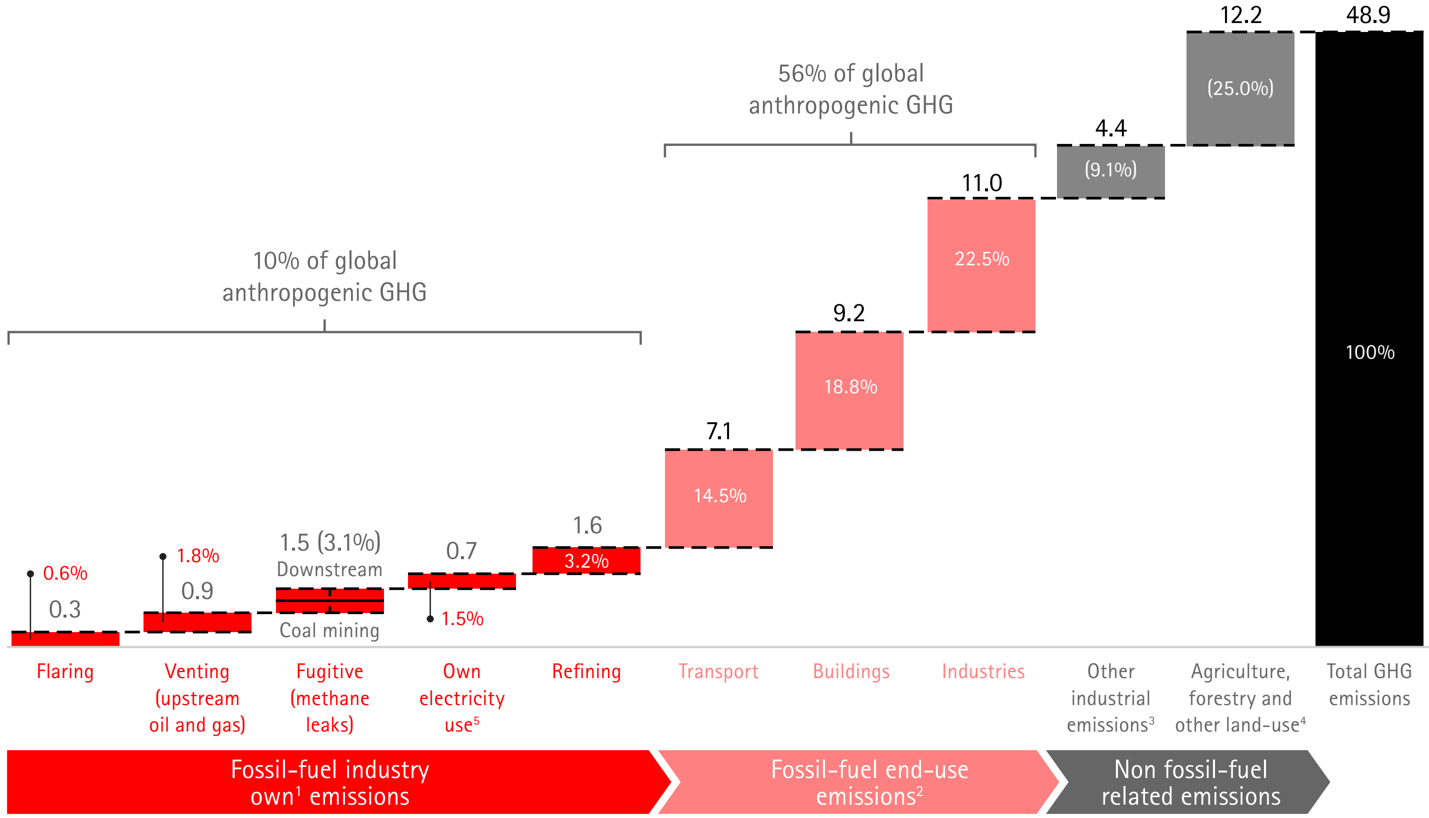
Note: Colors represent average stranded assets per region with potential significant differences between countries within a region.
Source: Adapted from Christophe McGlade, Paul Ekins (2015), "The geographical distribution of fossil fuels unused when limiting global warming to 2°C", Nature (vol 517)

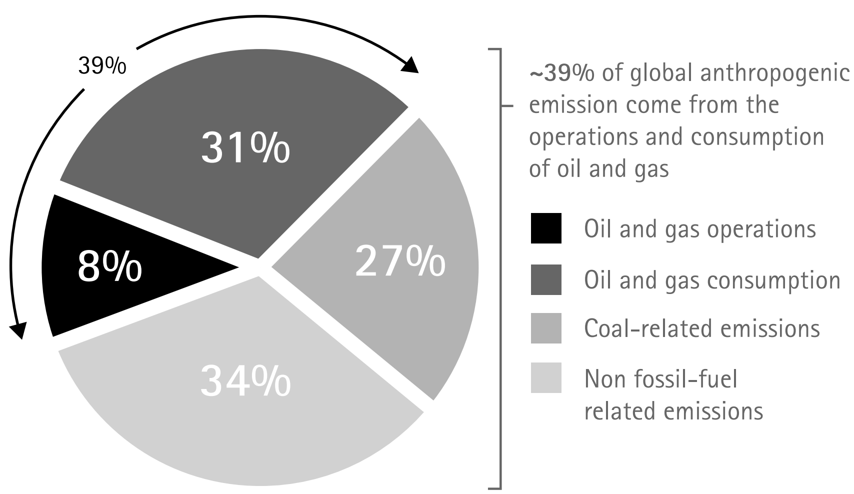
Capturing quick wins

While GHG emissions related to fossil fuels are mostly generated by their end uses, there is still a need to manage GHG emitted by oil and gas production activities.

In a carbon-constrained future, decarbonization efforts will have to be shared fairly among economic players, and that includes oil and gas companies. Although the fossil-fuel production industry (oil, gas and coal production, distribution and refining) cannot be held accountable for GHG emissions related to the final use of its products, it is directly responsible for emissions related to its internal industrial processes: Flaring, venting, leaks, refining and energy used for the production and distribution of these fossil fuels account for about 10 percent of all anthropogenic GHGs emissions, about one-sixth of the emissions related to the final consumption of these hydrocarbons via combustion or other oxidation reactions (Figure 12). Excluding coal operations, the oil and gas industry emits about 8 percent of global GHGs (3.8GtCO_2eq per year), emissions equivalent to 800GW of coal power plants.

Figure 12: Global anthropogenic GHG emissions in 2010





Notes:

[1] Exploration, production, transport, refining and distribution oil, gas and coal.

[2] CO_2 emission from fossil-fuel combustion and other oxidation processes in chemical or metal plants. Excludes emissions from diesel generators used to produce fossil-fuel, that are included in "own electricity use".

[3] Non fossil-fuel related emissions such as process CO_2 from cement production, or other GHG emissions from landfills, chemical production, steel etc.

[4] Includes methane and N_2O emissions from agriculture, CO_2 sources and sinks from afforestation and reforestation etc. Excludes energy-related CO_2 emissions for agriculture machines, which are accounted under "fossil-fuel combustion".

[5] Mostly from on-site diesel engines for production facilities. Excludes transportation fuel used for trucks etc.

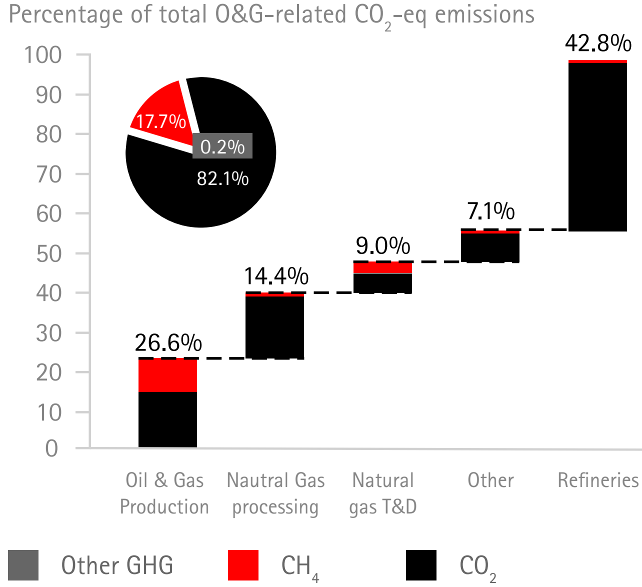
Source: Accenture Strategy, Energy analysis based on IPCC (2014) "AR5-WGIII"; Carbon Dioxide Information Analysis (CDIAC); and IEA, World Energy Outlook 2015

The oil and gas industry, therefore, has the potential to manage a significant share of the total carbon budget, potentially enabling additional hydrocarbon production and consumption if efficiently addressed

Oil- and gas-related emissions consist of about 80 percent carbon dioxide and 20 percent methane (Figure 13). These emissions have remained roughly proportional to the amount of fossil energy produced in the past 5 years[2]. Yet emissions are easier to abate where they happen to be highly concentrated: Firstly, companies could reduce the large CO_2 streams vented in the atmosphere at refineries and natural gas processing plants by separating, capturing, compressing and storing CO_2 deep underground at moderate costs ($14 to $70/t$CO_2$ avoided[3]) via a process known as CCS. Shell is investing $2 billion to demonstrate how to do this at commercial scale at the Gorgon gas processing facility in Australia. Secondly, in anticipation of ever-strengthening regulations, companies should eliminate flaring as quickly as possible by investing in local natural gas valorization processes[4].

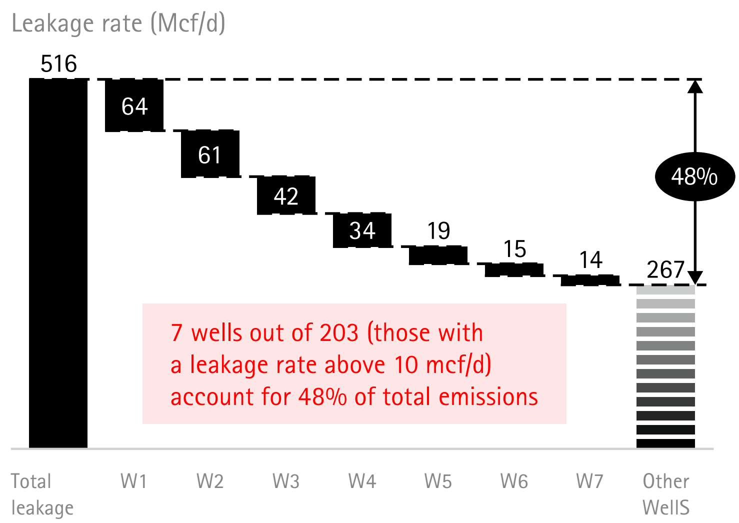
In terms of fugitive methane leaks—an extremely potent greenhouse gas, 28 times higher than CO_2 over a 100-year horizon—E&P companies have more immediate abatement potential in upstream than downstream: Detecting and focusing on the top leaking wells should be more cost efficient than refurbishing aging pipeline infrastructure (Figure 14). Finally, ambitious energy efficiency investments and off-grid renewable power supply systems should be promoted to limit the use of conventional on-site diesel generators[5] and compensate for the ever-diminishing energy-return on energy invested (EREI) of oil and gas production. EREI has been declining globally since the beginning of the 20th century, from 100 GJ/GJ invested in the early days to less than 10:1 today for conventional oil, and 3:1 for oil sands and oil shale[6].

Figure 13: Oil & gas emissions per facilities and per gas in the US (2014)



Source: US EPA (2014) - http://ghgdata.epa.gov/ghgp/main.do

Figure 14: Distribution of leakage rates across 203 wells in Fort Worth region



[2] IOGP (2015) "Environmental performance indicators – 2014 data", covering 40 oil and gas producers accounting for 29 percent of global oil and gas supply.
[3] SBC Energy Institute (2015) "Carbon Capture and Storage FactBook".
[4] Refer to initiative "Zero flaring by 2030": 20 new institutions have joined the initiative of the World Bank and the United Nations launched in April 2015. Among them are BP, Niger Delta Petroleum Resources, India's Oil and Natural Gas Corporation Limited joined Shell, Eni, Total and Statoil.
[5] Upstream energy-related emissions comes mostly (>80 percent) from on-site diesel generators.
[6] IPCC (2014) "AR5-WGIII" section 7.5.1

How serious is the Carbon bubble threat?

Predicting the future oil and gas business environment remains a highly speculative endeavor, as the COP21 agreement remains a fragile agreement from a quantitative and legal perspective. However, the factors discussed previously create uncertainty regarding E&P companies' future cash flows and, subsequently, their valuation and business models. That is especially true since the publication of a Carbon Tracker initiative's report in 2011, which highlighted concerns about the impending "Carbon bubble". How real is the Carbon bubble threat? Our assessment of post-COP21 climate-related constraints on E&P companies' valuation and business suggests it is certainly something oil and gas companies must be concerned about.

Oil and gas demand uncertainties

The carbon budget and related government initiatives to foster the energy transition away from fossil fuels will create further complexity in the oil and gas market and, consequently, increase oil price volatility while reducing oil and gas demand. In the past few years, the industry has shifted from "managing the peak oil with increasing demand" to "managing oversupply with softening demand growth." A decline in demand beginning in 2020, as required to comply with the 2°C scenario, could drive "lower forever" oil prices and reduce future cash flows. If that happens, oil and gas companies will experience ever-increasing business pressure, requiring more business agility and responsiveness. Although companies have been enhancing their business models well in advance of COP21, they will require a deeper transformation to respond to such pressure. Furthermore, uncertainties would increase business-related risk and might make lenders more reluctant to lend money to E&P companies. And government bonds' yield could increase in oil-driven economies.

Stranded assets

Because companies' stranded assets could not be produced, they would be written off at some point. However, the valuation impact should be limited in the short and medium term. Indeed, according to IHS, IOCs' proven reserves that will be produced in the next 15 years account for around 90 percent of their valuation. In other words, the COP21 agreement should not have a significant impact on companies' market value before 2030.

End of exploration activities and lower capex

Under a 2°C scenario, exploration would be stopped and development capex would be slashed. That means exploration risk would be eliminated, which should reduce E&P companies' WACC. This could be a positive development from a financial valuation standpoint. But as they eliminate exploration risk, operators will likely become similar to Oil Field Services companies, which would require a deep transformation of their current business models. One approach could be for E&P companies to shift to another staffing business model to match new business requirements: bring more flexibility, refocus skillsets and competencies, and remain attractive to talent.

E&P companies also should invest saved cash in value-accretive projects outside their traditional focus areas. That also implies a shift to alternative business models, such as massively investing in renewables or gas-CCS technologies to increase gas market potential. In the short term, when a project is scrapped, a company could return money to shareholders through share buy-backs or special dividends, which could have a positive impact on share prices. However, in the longer term, if companies find no viable alternative business model, the consequences could be extreme: They would cease to exist and the remaining net asset value would be given back to investors.

Potential massive divestment of fossil fuels stock holdings by institutional investors

In 2012, the NGO 350.org launched a "Go fossil-free" divestment campaign. The movement has affected around $50 billion in assets so far, a meaningless sum when compared with the $2.6 trillion energy sector market capitalization in the US alone. And 350.org has company. Several stakeholders—including the United Nations Environment Programme, asset manager AMUNDI, and not-for profit organization Carbon Disclosure Project—have launched a Portfolio Decarbonization Coalition, which is targeting $100 billion in divestment.

While gaining in profile, such divestment initiatives are insufficient to weigh on share prices—at least in the short term. However, as illustrated in Figure 15, their impact could be highly negative in the long run if such movements gain more momentum. That would be enough to get E&P companies to start thinking about alternative investments and business models. Nothing less than their existence is at stake.

Figure 15: Summary of valuation impact of climate change constraints post COP 21 agreement

	Future cash flows	WACC	Shareholder remuneration	Overall valuation impact
Stranded assets	Neutral at this stage			
Lower demand	Twofold negative effect = volume and price	Higher WACC	Negative	Negative
Lower development expenses	Positive in the long run if value-accretive projects are conducted	Lower WACC	Positive	Positive
Divestment campaign	Neutral at this stage			

Source: Accenture Strategy, Energy analysis

Conclusion

The COP 21 agreement leaves many unanswered questions—especially regarding the likelihood of successfully capping global warming to 2°C which, as we have discussed, hinges on the ability to significantly curb fossil fuel demand. Indeed, states have yet to implement constraining mechanisms to reduce the use of cheaper fossil fuels. Doing so could be politically sensitive if it results in higher retail energy prices.

The $100 million annual floor that rich countries pledged to grant to the poorest ones to fund energy transition beginning in 2020 is a positive and welcome development. However, the funding of the energy efficiency, renewables, and CCS required in a 2°C-compliant scenario have yet to be defined on a worldwide basis.

Perhaps the biggest wildcard is the uncertainty surrounding how states will react regarding their stranded assets. The current short-term race for market share in the Middle East and Russia could be part of a strategy to sell proven reserves before they become stranded.

Regardless of this uncertainty, the challenge for oil and gas companies remains the same: Just as they have successfully dealt with exploration and financial risks for decades, they now must include the CO_2 carbon budget as another major parameter of their portfolio management.

SECTION 3

Upstream Sector Lessons from Timor-Leste

How developing economies can attract capital and sustain development

An interview with Mr. Alfredo Pires, Minister of Petroleum and Natural Resources for Timor-Leste, by Philip Askew

The volatile oil market, while difficult for developed markets, is even more challenging for developing economies. Accenture Strategy Energy's Philip Askew spoke with His Excellency, Mr. Alfredo Pires, Minister of Petroleum and Natural Resources for Timor-Leste, on the lessons his country has learned on attracting capital and sustaining development.

Lesson 1

Ensure stability, confidence and manage resources for every generation.

Minister, how important is the energy sector in supporting Timor-Leste's development?

Timor-Leste has been managing the benefits and challenges of a dominant energy sector since the country gained independence 13 years ago. It was especially important as a new and post-conflict country. Following independence, the leadership firstly ensured the stability of our existing petroleum activities to give investors confidence and generate early revenue for Timor-Leste.

The benefits of our resources are being judiciously managed for the near and longer term through a petroleum fund based on the Norwegian model.

The fund holds about $17 billion in assets, returns around $400 to $800 million a year, and although this is challenged under the current economic climate, it has helped save for the future and stabilize revenues for the economy. This money is invested across the broader economy to support development of infrastructure, health, education services and other industrial sectors. Early diversification is also important: Timor-Leste has moved from 90 percent dependent on oil and gas to approximately 60-70 percent for its economy, largely driven by the fund.

Finally, as a new nation we sought assistance in upstream management, revenue management and environmental management from a number of nations, including Norway.

Lesson 2

Learn from others and get the industry structure and governance right.

Can you elaborate on the journey the energy sector has taken to balance the benefits and risks of such a sector, in particular the organizations and the governance?

Before we set up our industry structure, we looked around the world to see what other countries have done—for example, Norway. But we looked at not just what they did successfully, but also what they did wrong, so that we would not repeat those mistakes.

In terms of lessons, the first is around governance. We've installed transparency mechanisms through the legislature and have also leveraged learning and actions on transparency through global organizations (e.g. EITI).

We recognized the long-term benefits of a clear divide between the regulator (ANP), the National Oil Company (TIMOR GAP) and the manager of data and knowledge (Institute of Petroleum and Geology—IPG). ANP is managing the sector for licensing, compliance with standards and local content among other areas.

TIMOR GAP is only three years old, so following a focus on governance, they will shift to capability building and investment. IPG is developing capabilities and studies to support optimal management of natural resources. The three institutions have differences in opinion, but that's encouraged to minimize uncertainties and have as much information as possible.

These institutions are autonomous from the Ministry as the policymaker. The government can influence them through the Council of Ministers, by selecting the CEO and the board, but everything else needs to be competitively procured. That ensures sustainability for the long term, even when there are political changes, which is expected in a democracy. There's also an understanding between the Government and Opposition that oil and gas issues are of national interest and need to be handled at a level above politics.

Lesson 3

Invest to understand resource potential, ensure clear rules, and use this to help attract capital.

What particular lessons would you say other resource-rich emerging nations could learn?

First, if you're a new country or new to oil and gas, don't think you're new at this game. The industry players and many resource rich nations have been here for a very long time. One lesson is getting to know your resources very quickly. Put your energy, money and investors' money toward finding out what you actually have to maximize benefit to your country while attracting the right capital and capabilities to explore/produce your resources. By assessing what you have, you're able to negotiate more effectively. So find ways to identify your resources quickly and without sacrificing too much national secrecy, resources or interests. Make this information available. Here, we are in a global environment where competition is tough. There is commitment from our country's leadership to invest more money on resource assessment studies and on seismic surveys.

So what are the upcoming plans and opportunities in Timor-Leste's sector, especially at current prices?

We chose to go a bit slowly as we are learning the industry. So the last licensing round we did was in 2006, and that was a period in which we were managing some political issues. In an environment of low price, the upside is that things are getting cheaper—such as surveys. We've been talking to some major companies about what it would take for them to come over in this kind of environment and then work around that. We also have a look at what our neighbors are doing and what we can offer.

Timor-Leste's potential resources appear to be significant for a country of its size. What is Timor-Leste doing around these resources and how will you attract capital?

Recent studies indicate that Timor-Leste's prospectivity could be in the vicinity of six to eight billion barrels of oil equivalent. The government will invest more money to shore up those prospective volumes and then make the information available for the industry. We have commitment from the country's leadership to invest in our own data collection and studies (including seismic). This will support our potential partners in coming to Timor-Leste and investing in the upstream sector.

We are very flexible and if we define things properly in our contracts to avoid struggles, we can move forward. Past experience has shown us we have to protect ourselves if companies are not transparent or push too hard. We understand now where potential problems could come up and can, hence, work with our investors on a level playing field. Because petroleum is a long-term game, we will manage the issues as they come up. The country has demonstrated that not only are we able to talk about it, but we are able to find solutions.

Lesson 4

Build capabilities for the long term—balance local content requirements, investor requirements and the role of the National Oil Company.

How have you balanced the need to import capability to accelerate that understanding, versus building the capabilities from within?

We have a policy that says we need to participate in this sector. It takes seven to ten years to produce a fully qualified geoscientist, which is longer than a development. In addition, Timor-Leste is a young country, so you've got to also ensure private companies both bring in capability and invest in local content. Finally, your NOC also has a mandate to help increase capabilities.

The global industry is quite mature and there are standards that you need to meet. So as a young country, we have quite a lot of catching up to do to meet those standards. It's a matter of focusing and using the opportunities that come early on through projects and education.

We'll continue to develop specialized skills in some of the young people, but always keep in mind that those same young people can be used for other sectors, especially given their experience working under very high standards and in an industry that has a lot of uncertainty. So if they move on to another industry that has greater certainty, we'll have good people to manage the nation.

How are you using local content and your National Oil Company to help maximize and spread the benefits of the energy sector to the country?

We're still trying to define the term "local content," because you can almost do anything under that. It's part of the policies as a government that we need to participate in the development of people and also the local supply chain. It's also a policy that we need to diversify from just petroleum and it's clear how you can use local content to help with that.

Timor-Leste has funds available to help with basic education and degrees. That will be a government responsibility. But in more specialized areas, we talk to companies to help train our people, being equally aware that you cannot make it too cumbersome.

The National Oil Company is a pillar of many economies. How do you see TIMOR GAP playing a more active role locally and potentially internationally?

TIMOR GAP has a very specific role, but it's a commercial entity. Its basic role is to bring some money into the coffers and assist the country's economy. The government will be able to assist, but it must become commercial to survive, and that means building up its capabilities. We will make some requirements in our future PSCs about the NOC participation, but there is already a 20 percent back-in option in current PSCs for new discoveries. We face the challenge of getting ourselves organized so we can decide whether we can take the 20 percent in a certain timeframe or not.

TIMOR GAP is able to participate in upstream, midstream and downstream. Currently, the focus is on participating in exploration blocks and gaining skills, but we also have ambitions that in the future, TIMOR GAP can operate offshore and in other jurisdictions. We may not go everywhere. We may just go to very specific countries, but early on it will be with strong capable partners.

Lesson 5

Use funds from the dominant sector to create a diversified economy and a buffer against downturns.

How do you balance the potential resource curse of a dominant E&P sector?

We're trying to use the petroleum money to diversify and invest in non-petroleum activities. Because of diversification efforts, we have reduced our dependence on oil and gas from over 90 percent to approximately 60 to 70 percent at this stage.

Timor-Leste is also challenged by two very big, very capable neighbors: Australia and Indonesia. We need to find an additional niche, be that in tourism, agriculture, forestry and other areas. We must also invest in our people. In the past seven or eight years, we have sent our young people to study in all the places around the world. When we achieved independence, there were only six geoscientists, including myself. After 13 years, there are more than 500 Timorese with geoscience qualifications and of those, 100 have master's degrees from reputable institutions. The same applies for education across government, and education needs to be complemented with experience.

Is the current industry environment affecting Timor-Leste's energy sector?

The big impact is reduction in revenues: We can conservatively expect almost a 50 percent reduction. But we know that the price is going up and down. The establishment of the petroleum fund and accompanying regulations provide financial resources for us to weather this and act as a cushion. That is a recommendation that Timor-Leste would like to share with other countries. We know that other countries would like to spend that money on developing. But it's good management from the political bodies to communicate the position and get agreement to put some money aside, because it does not belong to the present generation, but to future generations.

So we look at this as a gift for Timor-Leste that it is temporary—whether it's 20, 30 or 40 years, in a span of history, it's temporary. The key is to determine what we're going to do with this money now for something that will be much more sustainable.

SECTION 4

A Three-Step Approach to Creating or Adjusting the Public Hydrocarbon Management Strategy to Weather the Storm

Authors: Raul Camba, Pablo Feher,
Philippe Parlange and Armando Zamora

In 1931, Harold Hotelling published his theory of exhaustible resources, starting with a simple question:

"How should exploitation take place for the greatest general good, and how does a course having such an objective compare with that of the profit-seeking entrepreneur?"

The recent plunge in oil prices and resulting transformation of the energy industry makes Hotelling's question more relevant than ever. In today's unique environment, producing countries must revisit the strategy they use to assess and exploit national oil and gas resources. They will have to more carefully think through future development to account for a low oil price and the industry's more cautious and cash-constrained mood.

Countries such as Norway, the United Kingdom, Colombia and Brazil have demonstrated the merits of a sound hydrocarbons management strategy (Figure 1). Since creating the Norway Petroleum Directorate (NPD) in 1972, Norway increased its production from 33 MBD to 3.4 MMBD in 2001 and is now managing the slow natural decline of its production. The United Kingdom increased production from 34 MBD in 1975 to 2.7 MMBD in 1985, 20 years after the first national licensing round in 1965. Colombia doubled production and increased oil proven reserves by 60 percent since it founded the Agencia Nacional de Hidrocarburos (ANH). And Brazil more than doubled its reserves 16 years after opening its market.

Figure 1: Countries' success metrics; 15-year period from local industry kickoff

Country	Oil production	Oil proven reserves	Total awarding rounds
	32x from 1972 (NPD foundation) to 1987	+360% from 1972 (NPD foundation) to 1987	34
	800x from 1970 (Forties Oil Field Discovery) to 1985	+125% from 1970 (Forties Oil Field Discovery) to 1985	42
	2x from 2003 (market opening) to 2014	+60% from 2003 (market opening) to 2014	8
	3x from 1997 (market opening) to 2014	+130% from 1997 (market opening) to 2014	16

Source: BP Statistical Review 2015; OPEC Oil and Gas Data, Accenture Strategy, Energy analysis

These countries' admirable track records can be attributed in large part to their focus on three key factors.

The first factor is geological information management and production forecasting: All four countries consolidate available information and estimate potential resources. Brazil sets its production goals based on three macroeconomic scenarios, while Colombia's plans are based on the need to satisfy domestic demand. Norway and the UK use operators' information and sanctioned projects (Figure 2).

The second factor is investment planning and promotion. Norway forecasts exploration and operation costs, sets investment targets, and evaluates and promotes investment opportunities. Colombia also promotes private investment in specific projects, while the UK focuses on partnerships for strategic projects. All four promote or directly invest in geological information acquisition where needed.

The third factor is industry collaboration: All four countries have established effective communications channels to incorporate industry's feedback into their processes. For instance, they receive blocks nominations before defining licensing rounds. Colombia and UK also update their fiscal regime to meet industry's expectations.

What can countries entering a new phase of national resource development or just starting to develop their domestic energy industry learn from these leaders? The biggest lesson is that they should develop public investment strategies to set a prudent pace of resources development. In doing so, they should answer three key questions:

- What should the nation's future production rates be, given its hydrocarbons potential?
- How should resources be exploited to best benefit public and private parties?
- What are the requirements to establish a sustainable and attractive environment for industry?

Figure 2: Main role of oil and gas authorities in selected producing countries

Role				
Evaluate potential resources	Excellent	Good	Good	Adequate
Manage geological information	Good	Limited	Excellent	Good
Set production goals	Excellent	Excellent	Excellent	Excellent
Define investment goals	Good	Good	Adequate	Not performed
Develop geological information	Limited	Excellent	Good	Limited
Assess and promote investment opportunities	Excellent	Excellent	Good	Limited
Foster industry partnerships	Excellent	Excellent	Limited	Not performed
Collect industry's feedback	Excellent	Excellent	Good	Adequate

Not performed   Limited   Adequate   Good   Excellent

Source: ANP, ANH, NPD, OGA UK official websites, Accenture Strategy, Energy analysis

A methodology to help governments manage resources in a competitive environment

The critical nature of public investment strategies—especially in today's volatile and competitive environment—calls for a formal, disciplined approach to strategy development. Accenture Strategy, Energy has developed such an approach, an iterative methodology that helps nations adjust their strategy, through three main steps (Figure 3):

- Assess the nation's potential resource base and set an optimal production goal
- Define optimal investment plans for each stage of conversion (pre-exploration, exploration, development, and production)
- Select the appropriate mechanisms to attract investors

Figure 3: The Accenture Strategy, Energy Public Resources Management Method

Source: Accenture Strategy, Energy analysis

A. Evaluating potential and defining optimal production

The starting point for strategy development or adjustment is to understand the nation's prospective and contingent resources, as well as its reserves.

This is done by assessing the nation's potential resource base, mapping the available geological information, quantifying the associated volumes, and estimating their degrees of uncertainty. This exercise enables a nation to identify areas where early and base geological knowledge must be developed, prospective areas, areas with exploratory activity, and areas with direct evidence of hydrocarbons. With such intelligence, governments are better equipped to select and prioritize areas most likely to help them achieve their goals.

Colombia's government opted to assess its resource based in partnership with a third party. In 2011, the ANH funded an academic study by the National University of Colombia to estimate the country's national hydrocarbons potential. The ANH used the study's findings to help the agency design a strategy for each basin.

But the volume of available resources is only part of the puzzle in setting the optimal production goal. The nation's political, economic, and social agendas are also critical. The oil and gas industry's contribution to a nation's agenda can, indeed, be political, as it increases national energy independence. From an economic perspective it directly or indirectly influences the development of the national industrial network and services offerings. And socially, it fosters high-quality job creation and regional development.

In addition, state participation in the economic return from the oil and gas industry generates public income that can represent a significant source of funding for other government priorities. For example, the Brazilian Ministry of Mines and Energy developed a sophisticated model to set national production targets. The model considers several key inputs—including GDP growth, fiscal and monetary policy, foreign direct investment, and energy consumption and supply—and verifies macroeconomic consistency with such variables as investment rate, balance of trade, net debt and current account balance.

Another factor that's especially important in the current context is the country's relative attractiveness compared with other nations. In a high-oil-price environment—with its implicit assumption of oil scarcity—it was easy to assume that oil would be produced as long as it met internally consistent economic production criteria. Today, it's evident that cash will only flow to the most competitive resources, which means an in-depth understanding of the relative profitability terms among nations is critical. IOCs have long had the ability to analyze their international portfolio to gain such insight. Today, that ability must also be a basic element in modern oil and gas regulators' analysis tool kit.

The bottom line: The optimal production goal will effectively balance the nation's agenda with identified potential resources.

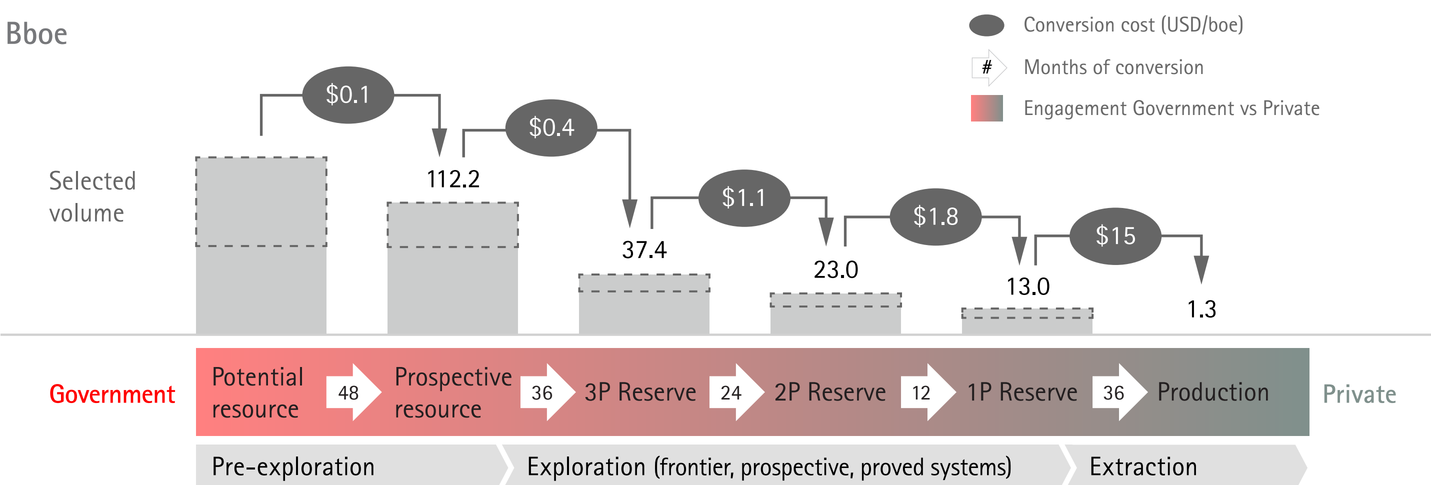
B. Characterizing the conversion funnel

After identifying its optimal production goal, a government must convert the goal into investment plans through a process of reverse design via the "conversion funnel" (Figure 4).

The conversion funnel estimates the required volumes to move from one stage of maturity to the next—e.g., from prospective resources to potential plays, to 3P reserves, to 2P reserves, to 1P reserves, and ultimately to the defined production goal.

For each stage of maturity, the conversion funnel helps a government define appropriate volumes, considering such key factors as national reserve replacement target, likelihood of successful awards in auctions, and likelihood of awarded volumes' geological conversion success.

Figure 4: Conversion funnel by stage



Volume tendered	NA	25.1	10.0	6.0	4.8	Bboe
Awarding success	NA	30.%	30.%	30.%	30.%	%
Awarded volume	25.1	7.5	3.0	1.8	1.4	Bboe
Conversion factor	30%	40%	60%	80%	90%	%
Converted volume	7.5	3.0	1.8	1.4	1.3	Bboe
Total investment	$0.65	$1.30	$1.95	$2.60	$19.50	B USD

Source: Accenture Strategy, Energy analysis based on the Mexican Case, PEMEX - Hydrocarbon reserves at January 1st, 2015

Once it has assessed the required volumes by stage, a government can determine the geological information required to convert these volumes and estimate the corresponding required investment. The government can then decide to invest directly or through strategic partnerships in specific areas and stages of maturity, or to call in the private sector to invest—either in partnership or on its own. The Oil and Gas Authority (OGA) of the UK, for example, developed in 2015 a complete strategy and investment plan to increase the scope and reliability of geological data. The authority eventually funded seismic surveys in under-explored areas of the UK Continental Shelf to accelerate exploration and promote interest in frontier areas.

In areas and stages of maturity where the government is unwilling to assume the risk alone, it can devise a wide range of investment mechanisms beneficial to private players (Figure 5). For instance, multi-client studies upgrade the quality of the geological information without involving risk to oil companies or government expenditure. Public-private partnerships split the risk between the parties and foster information sharing between public and private actors. Technical evaluation agreements reward the risk taken by oil companies with some privileges during bidding rounds. And nominations that give oil companies the opportunity to identify the blocks in which they are most interested enable authorities to improve the likelihood of success when preparing the licensing rounds.

And assessing both public and private benefits

Contrary to intuition, larger government investments in early stages (pre-exploration and exploration) can actually increase tax and royalty collection and improve the chances of success for tenders. A more robust initial geological information database enables authorities and industry to identify attractive, low-risk areas that will demand a premium during the bidding processes.

Figure 5: Investment mechanisms

	Government direct investment	Multi-client studies	Public-private partnerships	Technical evaluation agreements	Nominations
Description	Geological information developed by the government to attract future investors	Permits for geoscience companies to acquire geological information in certain areas	Partnership between government authorities, geoscience companies and operators to share geological knowledge	Contract for operators to evaluate resources in a block and identify prospects	Operators propose areas they are most interested in, so the authorities include them in the licensing blocks
Benefit	Increase awarding success in auctions	Sell information to operators interested in bidding	Government holds control of information and promotes collaboration among players	Exclusive right to convert areas in E&P contracts, right to match offer during auctions	Tender the most attractive blocks to the market
Example	• OGA (Oil and Gas Authority) • 20 million pounds investment to acquire 2D seismic in the UK Continental Shelf (2015)	• CGG • 3D Seismic in the Barreirinhas basin to be sold to industry players (2015)	• Common Data Access Ltd. (CDA) • Association led by O&G UK and with more than 40 operators as members dedicated to share geological information	• Colombia's National Hydrocarbon Agency (ANH) • Assigned 10 technical evaluation agreements to operators like Shell and Repsol (2010)	• Norwegian Petroleum Directorate • Received nominations from 40 different operators for the 23 licensing round (2014)

Source: Accenture Strategy, Energy analysis

C. Ensuring everything is in place to make things work

Better and more complete geological information (acquired according to the previously defined investment plans), in turn, entice private operators to bid for exploration and production blocks.

Setting the right mechanisms to allocate these blocks is as critical as the previous steps to ensuring expected production targets are met. Governments must tailor their auctions to engage the most relevant companies by presenting a thoughtful selection of the areas on offer; defining the business models in which the companies will operate (e.g., profit-sharing, production-sharing, license or service contracts); delineating the minimum conditions for participation (including investment required, local content, and safety and environmental standards); and using the appropriate auction format (single round, multi-round, single item, combinatorial and award criteria).

Governments should not underestimate the importance of these factors. For example, high local content requirements in the Brazilian 2014 bidding round effectively drove away many private investors; the government awarded only 37 out of 266 blocks on auction. On the other hand, the oil and gas fiscal regime reform was a key factor in the success of the 28th round of UK Offshore Licensing. The UK government awarded 353 blocks in that 2015 auction, making it one of the largest rounds in five decades. The OGA UK maintained a constant and deep communication with the industry to identify the best acceptable mechanism.

Indeed, effective and clear communication channels between the industry and the authorities are vitally important. They deepen the government's understanding of industry perspectives, increase process transparency, and improve the authorities' credibility (Figure 6).

Figure 6: Examples of communication channels with the industry

	Description	Topic	Audience	Frequency
Online surveys	Web portal with general questions to compile the industry perception and receive suggestions for the process	Industry overall perception	All industry players	Continuous
Public hearings	Open call to present face-to-face special subjects and receive direct suggestions in this regard	Presentation of plans, contract terms, blocks, awarding schemes, among others	All industry players	Quarterly/ ad-hoc
Focused surveys	Questionnaire to compile the detailed POV of specific topics from main industry players	Perception of specific topics as required, including investment, future licensing rounds, deduction schemes	C-1 depending on topic (e.g. Exploration VP)	Semi-annual
Personal interviews	Individual interviews with oil company executives to understand their strategic objectives, scope and expectations for the country	Strategic objectives and main concerns of potential investors in the country	CEO/Country Manager	Annual

Source: Accenture Strategy, Energy analysis

Conclusion

Developing the right national hydrocarbon strategy is a complex undertaking that is fraught with risk.

A government must identify an optimal production goal that not only maximizes potential resources utilization, but also serves the nation's political, economic, and social agendas. And that's just the beginning. Equally important (and difficult), a government has to develop a clear investment plan that defines the appropriate level of government engagement and private investors' roles, and implement a block allocation mechanism that private investors find attractive.

As if that's not challenging enough, there's also the issue of sustaining what the government develops. Energy policy makers must ensure the long-term stability of the objectives they set for the country, avoiding disruption by political and corporate cycles that could make private investors skittish.

Energy policy makers really have no margin for error, and that's especially true in today's volatile and competitive environment. By following the three-step approach just outlined, a government can create a robust energy policy that will help the nation weather today's storm and put it on the course to future prosperity.

SECTION 5

Using the Oil Price Crisis to Transform

Five imperatives for North American E&P Players in 2016

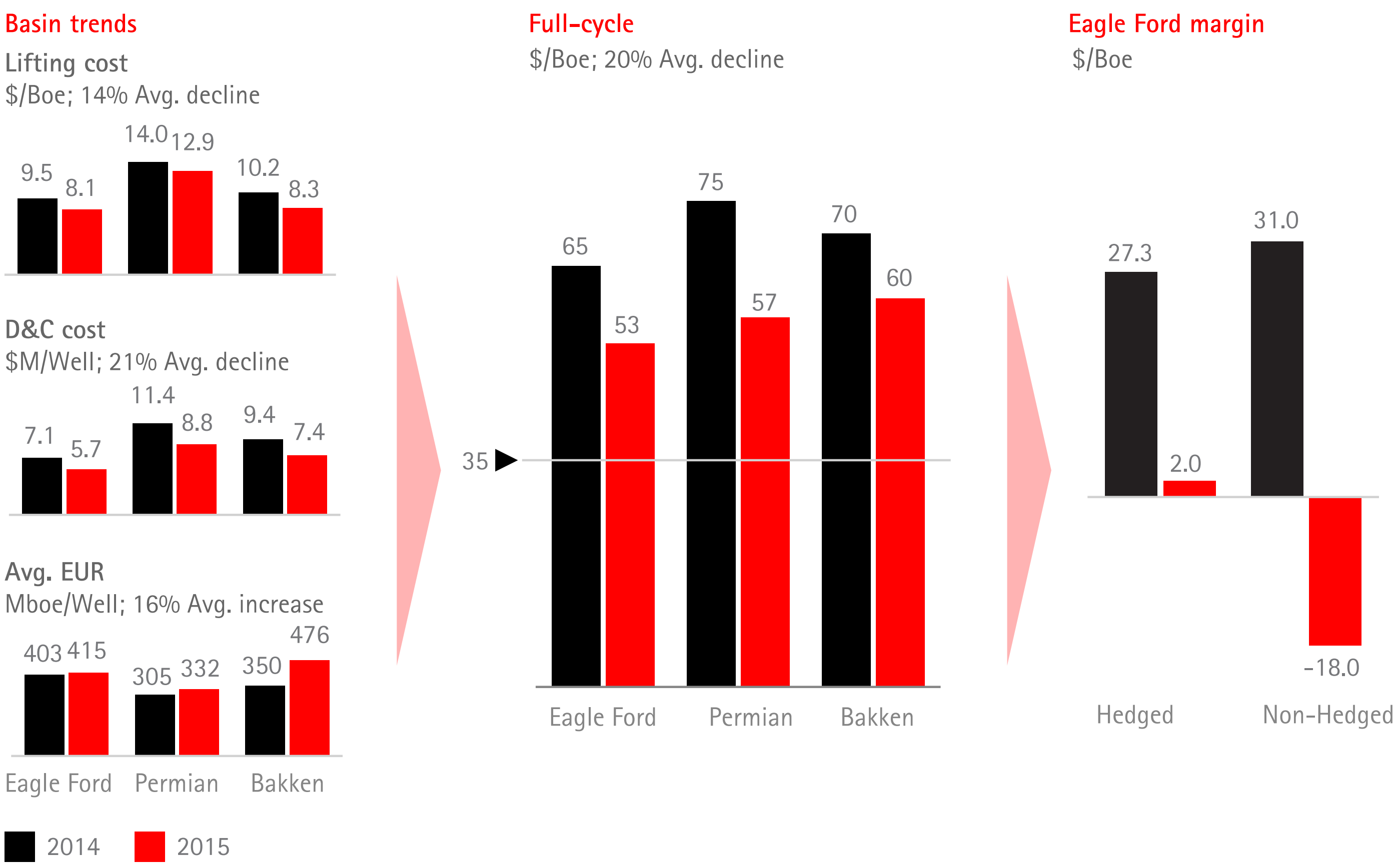
Authors: Muqsit Ashraf, Thomas Bonny, Nuri Demirdoven, David Rabley and Mo Saadat

Last year was an eye opener for North American oil and gas, even more so than for the industry globally.

Beginning in late 2014, supply-driven imbalance triggered by gravity-defying growth in tight oil production and an equally stubborn response from OPEC sent prices, and consequently rig count, crashing.

North American operators and service companies were quick to dust off their trusted playbooks of yesteryears and revisit the tricks that had helped in previous low-price cycles: cutting headcount, squeezing suppliers, scratching strategic initiatives, and divesting the most obviously underperforming assets. And much of this worked: Costs are down, production held and break-evens have decreased (Figure 1).

Figure 1: Market changes in major US oil plays



- There is 19% avg. decline for avg. weighted oil break even
- In 2015 hedges were able to keep positive cash margins
- Most of those hedges will expire in 2016
- Anticipate negative margins for new wells in several plays

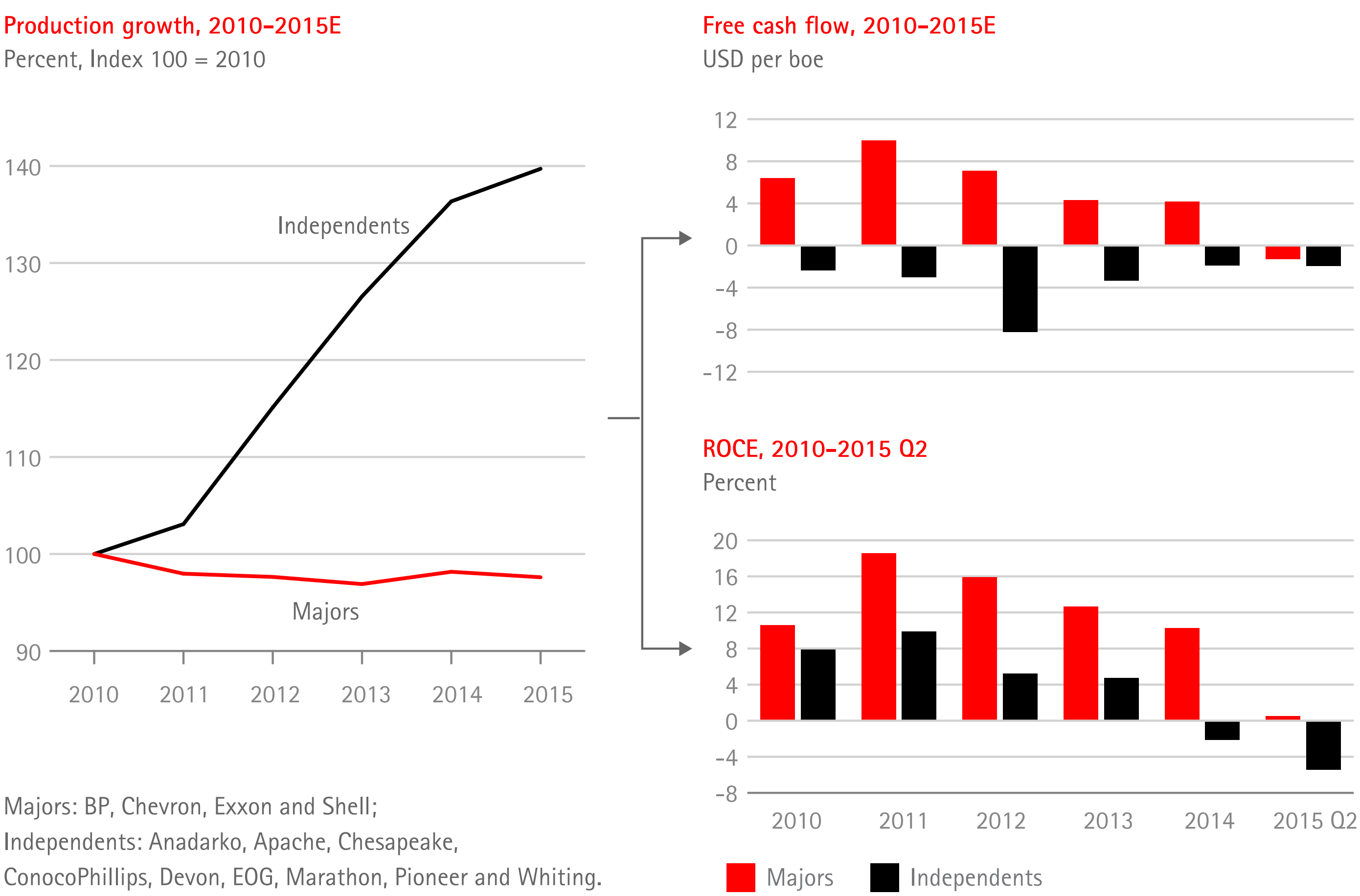
Source: Accenture Benchmark Analysis, IHS, Company Reports, Drilling Info, Wood Mackenzie.
Note: Cash Margin calculated based on average cost and production in Eagle Ford. Margin is equal to price adjusted for BE cost and cost of hedging. No hedging cost in 2015 due to the lack of hedging options.

Yet successful as these efforts have been, they are neither sufficient nor sustainable—particularly as low commodity prices may be with us for much longer than was the case in 2008-9 and the hedges that shielded operators in 2015 largely run out. North American operators enter 2016 in a tenuous position: Their operating cash flows already often fail to cover required capital expenditures, and now put them at risk of being unable to meet their debt commitments. This time, they can't simply ride out the cycle. Instead, rather than a "revisit," the industry needs a fundamental rethink, and quickly.

Applying old tricks and expecting a different outcome?

The oil and gas industry was at a crossroads well before the most recent downturn hit (Figure 2). The sector's financial performance was declining even as US production reached record levels. Growth in Lease Operating Expenses (LOE), Capital Expenditure (capex) overruns and major project delays, organization capability gaps, slowdown of innovation, and divergent performance focus all hit hard as the prevailing emphasis on production and reserves growth at any cost collided with the capital markets' greater (and rightful) pressure for margin and returns improvement.

Figure 2: US Production vs ROCE



Majors: BP, Chevron, Exxon and Shell;
Independents: Anadarko, Apache, Chesapeake, ConocoPhillips, Devon, EOG, Marathon, Pioneer and Whiting.

Source: IHS; Rystad

The painful truth is that the industry's lack of structural reform of its operating model and limited appetite to reinvent itself even during periods of crisis left the players ill-prepared to deal with a strong cyclical downturn. What we now see is a case of doing "too little, too late".

1. Putting assets on the block quickly to generate cash: Companies have started selling assets and acreage without assessing the underlying root causes of their performance and determining how to realign the overall portfolio with their strengths and objectives. Make no mistake, most operators' portfolios need to be trimmed or adjusted—but it must be done judiciously to ensure sustained impact.

2. Reshuffling caretakers without refocusing the operating model: Too much attention has been spent on updating boxes and lines, or spans and layers, and too little on building an operating model and capability set that foster corporate strategy and performance improvement.

3. Squeezing suppliers and expecting price concession gains to endure and carry the day: The industry has seen this movie before. When times are tough, operators squeeze suppliers hard. When markets are stronger, suppliers push prices up. It's a zero-sum game, where any gains eventually erode as operators and suppliers fail to collaborate for mutual longer-term benefit.

4. Freezing spend on strategic, long-term initiatives and capabilities: The emphasis on lower costs today causes players to postpone or cancel transformative initiatives, such as digital or new technology adoption. Doing so risks delaying improvements until long after the cycle turns and prevents progress in building those critical capabilities needed to survive in the long run.

5. Slashing headcount and spending as the primary cost-reduction vehicle: In good times, new activities tend to mushroom. In bad times, companies often make blanket cuts without first assessing which activities they truly need. Cutting spending without being sure what drives the balance between production and cost makes it really difficult to understand where and how to improve.

The industry simply cannot afford to continue down this path. It must seize and leverage the opportunities inherent in this crisis to develop a model and a mindset that prioritize profitable barrels over barrels at any cost to radically enhance the industry's long-term performance. We have identified the five imperatives the industry must act on—quickly, at scale, and through an integrated approach—to weather the current storm and position itself for future ones. There is no time to delay.

1. Reform portfolio dynamically through higher resolution (Hi-Res)

Dynamically high-grade within the core

Portfolio choices are critical for an operator's long-term success. A sure and fast way to make such choices is to concentrate on developing assets with low enough breakeven points.

Obvious? Yes. Done? Hardly. Result? By our count, about 25 percent of wells in the Eagle Ford were sub-economic in 2014, with average WTI of over $90 per bbl. In 2015, the number jumped to 55 percent as the average WTI fell below $50 per bbl. The situation is worse in Bakken, where even leading performers there have fallen short in reversing this trend. Oil and gas companies overall have been too slow to parse their portfolios and have yet to materially shift their focus from non-core to core assets.

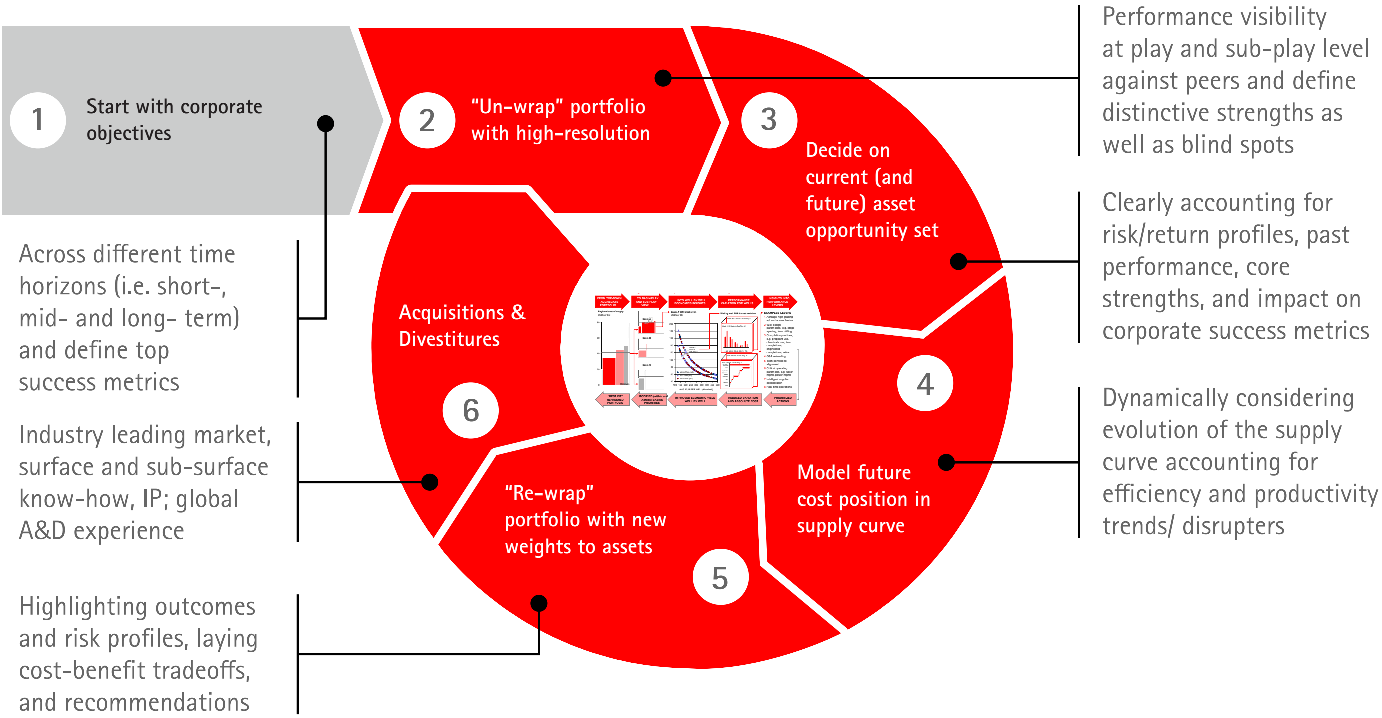
Our experience and analysis show that operators need a structural break: They must step away from historical reliance on traditional strategic planning driven by the budgeting process and take a dynamic, high-resolution look at their portfolio. By dynamic and high resolution ("Hi-Res"), we imply a planning process with more frequent portfolio decisions that incorporate a) comparative well-by-well economic performance rolling up from sub-play to play and to basin/asset level; b) learning effects within and across assets; and c) technology impacts. Adopting a Hi-Res approach is mission critical for operators with shorter-cycle assets such as tight oil, shale gas, and onshore conventionals that dominate the North American portfolio.

We recommend a six-step Hi-Res approach (Figure 3) to shape up portfolio results. The most critical steps are to:

- Align the portfolio with corporate objectives to identify the top metrics that define success.
- Gain performance visibility down to the sub-play level to assess performance against peers. This enables operators to understand specific strengths and improvement opportunities and, in turn, decide which parts of the portfolio provide the best current opportunity.
- Model future scenarios to assess how technology and other efficiencies change the cost and revenue paradigm.
- Determine where to focus activity and where acquisition or divestiture portfolio decisions need to be made.

Figure 3: High-resolution performance visibility framework

Accenture Strategy's step-by-step dynamic portfolio management framework based on high-resolution performance visibility

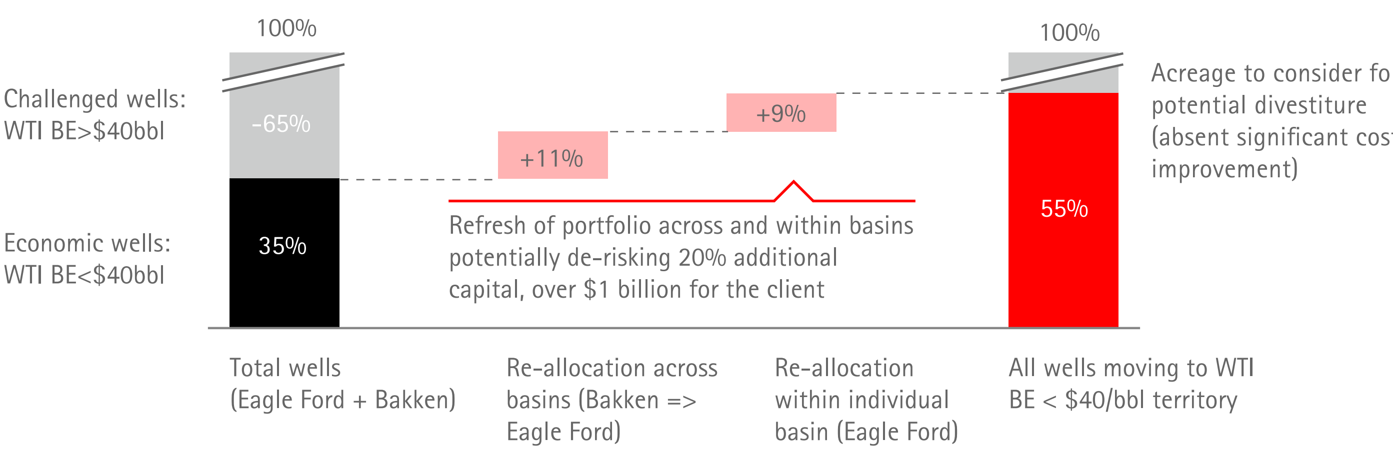


A sample of wells in Bakken and Eagle Ford illustrates how the Hi-Res approach can improve returns (Figure 4). According to our analysis, the Hi-Res approach would allow a third-quartile player to shift its portfolio toward more economic wells so that ~55 percent of its assets break-even below $40 WTI, compared with 35 percent doing business as usual. The remainder of the assets could be potential divestiture targets if the company could not uncover additional cost or production improvements.

Figure 4: Impact from high resolution performance visibility on client

Distribution of well for break-even WTI

Percent



Note: Break-even analysis assume 2014 estimated EURs and 2015 costs, reflecting price deflation and other efficiencies for 1,200 wells of the leading and average players. Source: DrillingInfo, Wood MacKenzie, IHS, Accenture Strategy, Energy

2. Create coherence between strategy and operating model

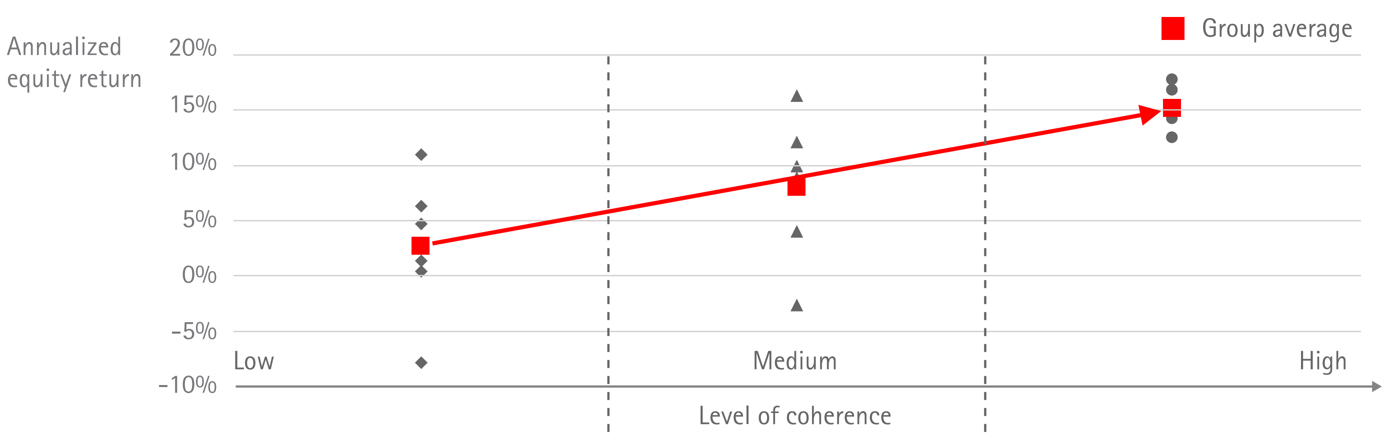
The pace of unconventional development in North America caught everyone by surprise, including domestic operators.

During the initial boom phase, few if any operators had the time to crystalize their strategy, assess their portfolio, and define the organizational construct and capabilities required for long-term value generation. Operators rushed to scoop up acreages across the US while erratically disposing or deprioritizing their conventional positions. The result in many cases was a hodge-podge of assets and capabilities. The inability to align the corporate strategy with the right operating construct led to greatly divergent results, with low performers yielding less than one-third of the shareholder returns of companies with strong strategic and operational coherence (Figure 5).

The current downturn has given everyone in the industry an opportunity to reflect on the path forward. Those carrying myriad asset classes should first clarify their strategy in terms of growth priorities within the portfolio and define their competitive differentiators. In North American resource plays, for instance, it may come down to attaining the lowest unit cost per barrel—driven not just by the absolute cost of a well, but also by enhancing well productivity through technology.

The organization must then define the structure and construct to support the strategy. This structure should delineate clearly distinctive businesses and identify whether an asset-centric or functional model is optimal for each business type. For resource plays, an asset-skewed hybrid is likely ideal, giving operations more decision-making flexibility and agility.

Figure 5: Equity return vs level of strategic-operational coherence



	Low	Medium	High
Portfolio	Significant dispersion; and/or adjustments over time	Shifts over time, but focused on a few asset classes/ geographies	Clear core/growth focus and capital discipline
Organizational structure	Constant shuffling; BU organization haphazard; and/or lack of clarity between assets and functions	Evolving structure/construct; good foundational capabilities and limited overlaps between BU and functions	Organizational structure fit for purpose; role of BU and functions clear; distinctive capabilities

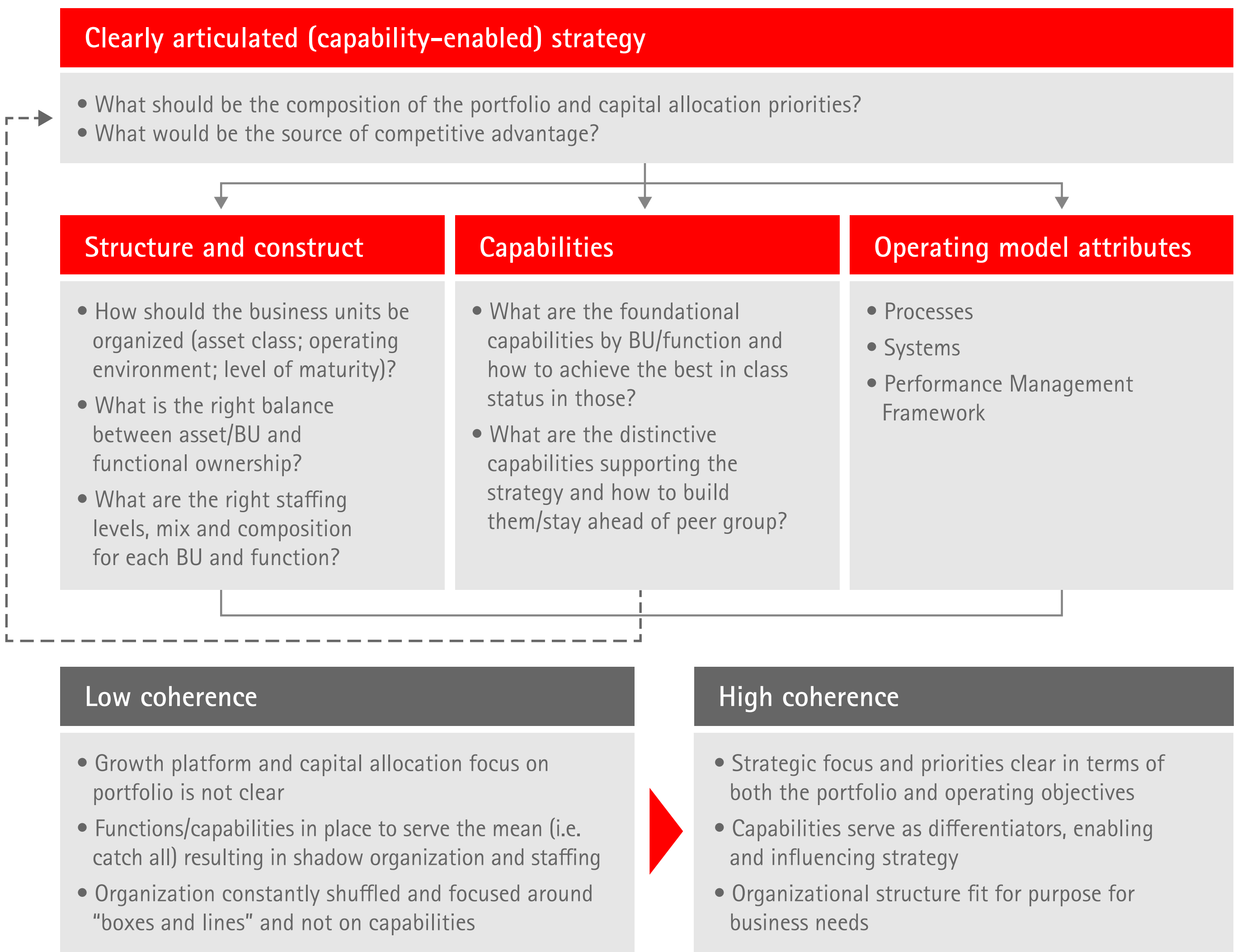
Source: Equity return adjusted for dividends and splits: RRC, OXY, EOG, PXD, CLR, NFX, APC, DVN, SWN, NBL, HES, MRO, APA, MUR, ECA, HSE, TLM

In this respect, North America onshore has been plagued by three primary issues:

- Adapting conventional technical and operational personnel and competencies to serve unconventionals or maintaining central groups that try to serve both
- Devoting limited attention to advancing foundational capabilities such as planning and supply chain that are critical to a high-resource-intensity environment
- Underinvesting in distinctive capabilities such as innovation and analytics required for the future

Correctly applied, technology can reduce completions cost by 50 percent by eliminating non-productive frac stages, and enhance well productivity by 50 percent by optimizing the placement and design. The net result can easily outstrip incremental gains from further leaning out well delivery and squeezing supply costs. Similarly, deploying real-time monitoring centers and analytics can shift the cost curve by reducing non-productive events such as side-tracks, predicting equipment failures, better identifying sweet spots, and providing performance visibility. Developing such skill sets requires an intentional focus on capabilities aligned to the portfolio.

Figure 6: Aligning corporate strategy to organizational constructs



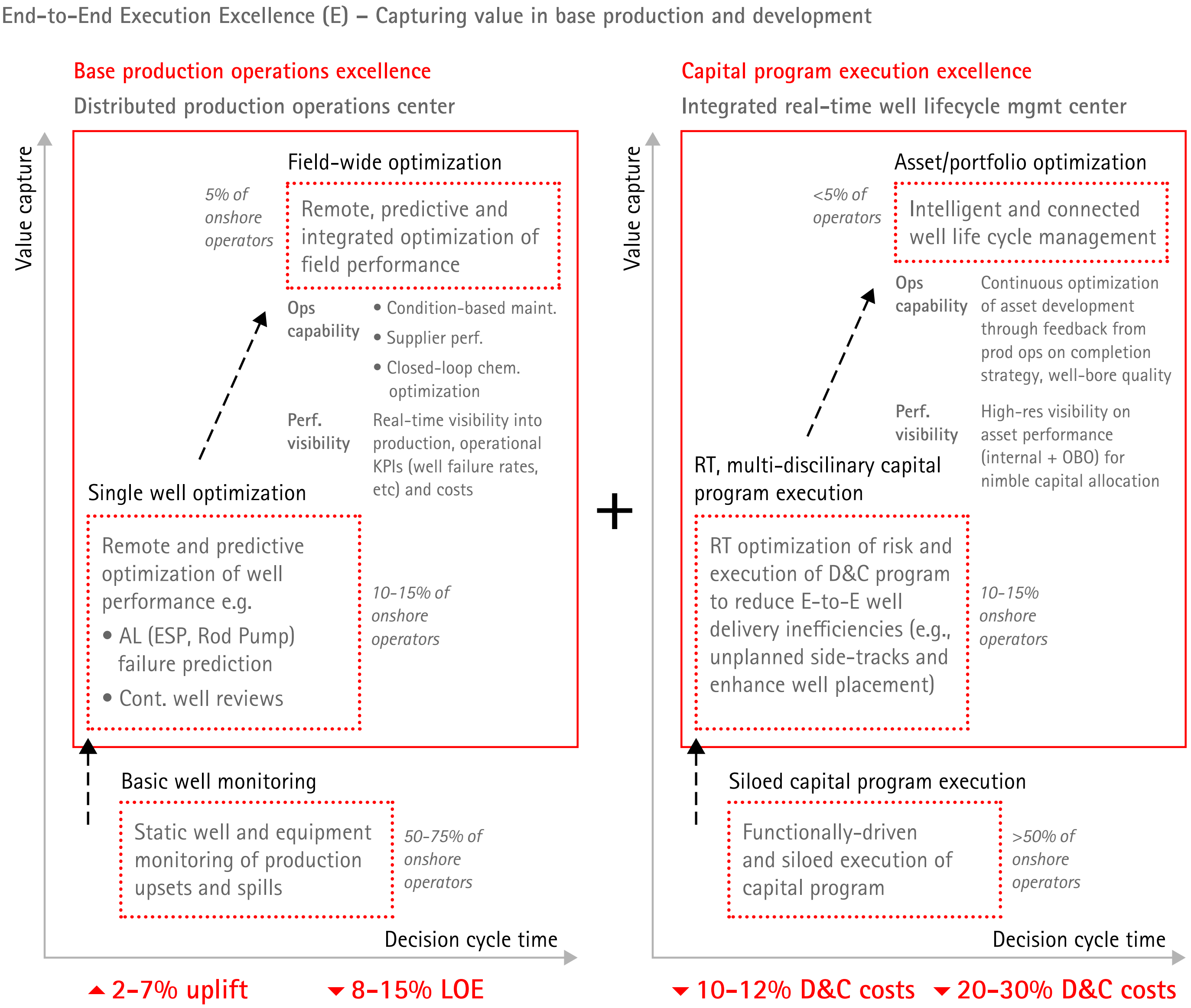
3. Seek end-to-end execution excellence (E4)

Re-align the performance culture, optimizing returns and cash flow ahead of production growth.

In the first wave of resource development, the North American unconventional industry's mantra was production growth at all cost. This must switch to unit cost focus across the entire well lifecycle.

Operators must continuously identify improvement opportunities in real time, and then promptly leverage the experience of cross-disciplinary teams to capture them.

Figure 7: Capturing value in base production and new development



Note: UR E4 = Unconv. Resource End-to-End Execution Excellence, RT = Real Time, CoE = Center of Excelence

This new way of working, as embodied in Figure 7, requires four key operating constructs:

1. Establish multidisciplinary remote decision centers with functional specialists (drilling engineers, production analysts, etc.) who have real-time visibility into operational performance

2. Deploy fully integrated end-to-end work flows with cross-disciplinary asset teams that have full decision visibility across the well lifecycle—for example, drilling engineers working in sync with geologists/geo steerers on drilling plan changes, or drilling engineers consulting with production engineers on hole sizes to ensure the application of electric submersible pumps

3. Grow proactive and predictive analytical capabilities to identify potential operational disruption and recommend appropriate action (such as uncovering drill string or artificial lift equipment failures)

4. Apply continuous improvement practices (such as Lean) to drive out waste or inefficiencies from repeatable processes, such as the well delivery or the reservoir characterization process

Applying these principles can have a dramatic impact on both base production management and capital project execution.

In base production management, we have helped operators apply these principles to transform their operations from rudimentary well monitoring to well optimization. Ultimately, these principles can help drive full field optimization, including chemical management, subsurface and surface maintenance, and water management. An operator in the Delaware basin, for example, used to manage its workovers ineffectively, "prioritizing" jobs based on whoever screamed the loudest. Starting in 2014, it began managing workovers centrally within the asset to provide better visibility and the ability to prioritize workover rigs based on NPV. The result: a 20 percent cut in workover rigs and a 50 percent cut in rig-up to rig-down time.

In unconventional capital project execution, newly formed integrated asset teams (including reservoir, geology, completion, production and drilling engineers) collaborate in real time to reduce well delivery inefficiencies (such as unplanned sidetracks and high dogleg severity). Further, a digital analytics capability and high-resolution performance visibility can optimize subsurface characterization and completion design techniques to enhance overall reservoir recovery.

4. Make suppliers collaborators

Go beyond a zero-sum game by building an Intelligent Collaborative Supplier Ecosystem (ICSE).

The supplier squeezing phenomenon has again been on display in the recent downturn, with cost deflation of 25 percent to 35 percent across major well construction categories.

While important, these reductions have been the result of unsustainable brute force, win-lose negotiations—with the result that even leading OFS players have reported quarterly losses in 2015. Clearly, a new approach is needed.

The path to sustainable improvement can be found in parallel capital-intensive industries. These include the automotive, aerospace and high-tech sectors, which transformed their supplier relationships in the past two decades by creating supply ecosystems organized around value. The oil and gas industry should and can achieve a similar, though more rapid, transformation through an Intelligent Collaborative Supplier Ecosystem (ICSE). The ICSE makes supplier relationships value accretive across the business cycle through four key pillars (Figure 8):

1. Strategic Realignment

Operators directly align their supply chain performance metrics with corporate priorities, and empower the supply chain organization at the center and within the assets to assume responsibility for decision making.

2. Intelligent Supply Chain

Operators immediately take a high-resolution approach to their priority cost and production metrics—well-by-well as needed—across suppliers. Doing so will enable operators to not only reduce performance variation, but also to design out-of-the-box collaborative and commercial strategies. In the mid-term, operators should build additional intelligence into their supply chain through demand/supply planning and new digital applications.

3. Dynamic Collaboration

Operators incorporate supplier feedback in design, include them in the planning process, and eventually integrate them into the extended design and delivery lifecycle. The outcome is a value-oriented partnership focused on accelerated learning.

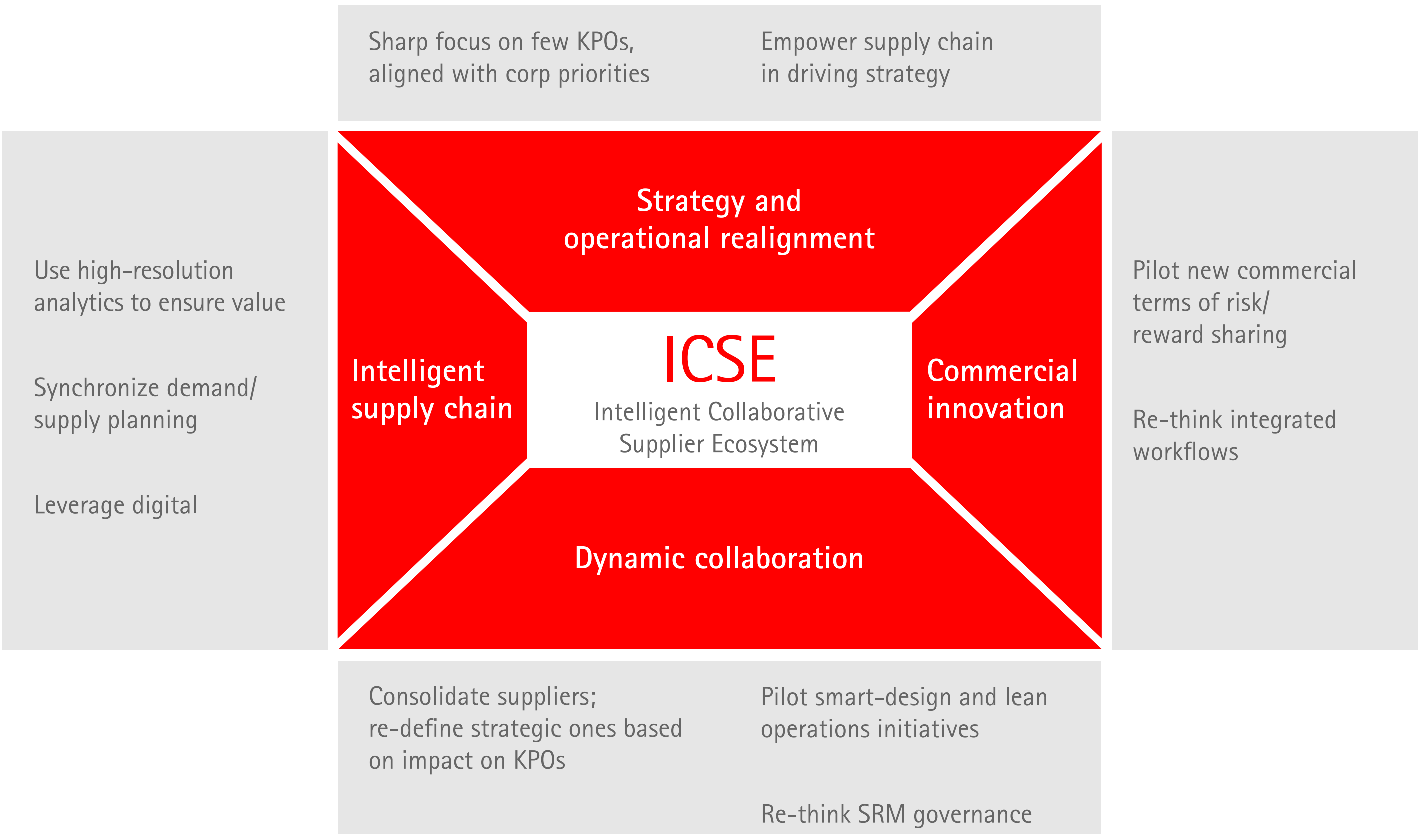
4. Commercial Innovation

Operators change the spirit of contracts from protection of interests that are at times conflicting to alignment of interests on value—cost, production or both—and drive competition accordingly.

Figure 8: ICSE Framework

ICSE is an intentional structure formed by multiple supply players of different tiers and their end customer working together to improve capital performance by 30 to 40 percent, above and beyond what they can achieve individually

Accenture Strategy's ICSE Framework



The result of the ISCE approach is a step-change reduction in cost, increased production, and accelerated time to delivery of wells and projects due to smart (standardized) designs and learning-curve benefits from replicating the outcome. For example, one leading operator employed a modified version of this approach for a project comprising two truss spars in the Gulf of Mexico. In doing so, the company reduced engineering hours for spar and platform by 60 percent, cut the topsides procurement cycle in half, and ultimately saved $1 billion with 18-month schedule acceleration.

In another example, a leading operator in the Eagle Ford used a collaborative approach to determine it could boost its efficiency in completing and stimulating wells by a dramatic 200 percent to 300 percent. This operator had previously targeted just 20 percent gains before opening up the solution space to full collaboration with its strategic supplier. A joint team comprising executives from both companies focused on identifying, approving and implementing an enhanced, standardized approach to completing wells and establishing reliable consistent operations in the field. Within three to four months of launching the collaborative effort, the operator and its suppliers captured 50 percent gains through a set of joint quick wins, thus materially improving economics in the play.

5. Bank on distinctive capabilities in innovation, digital and analytics

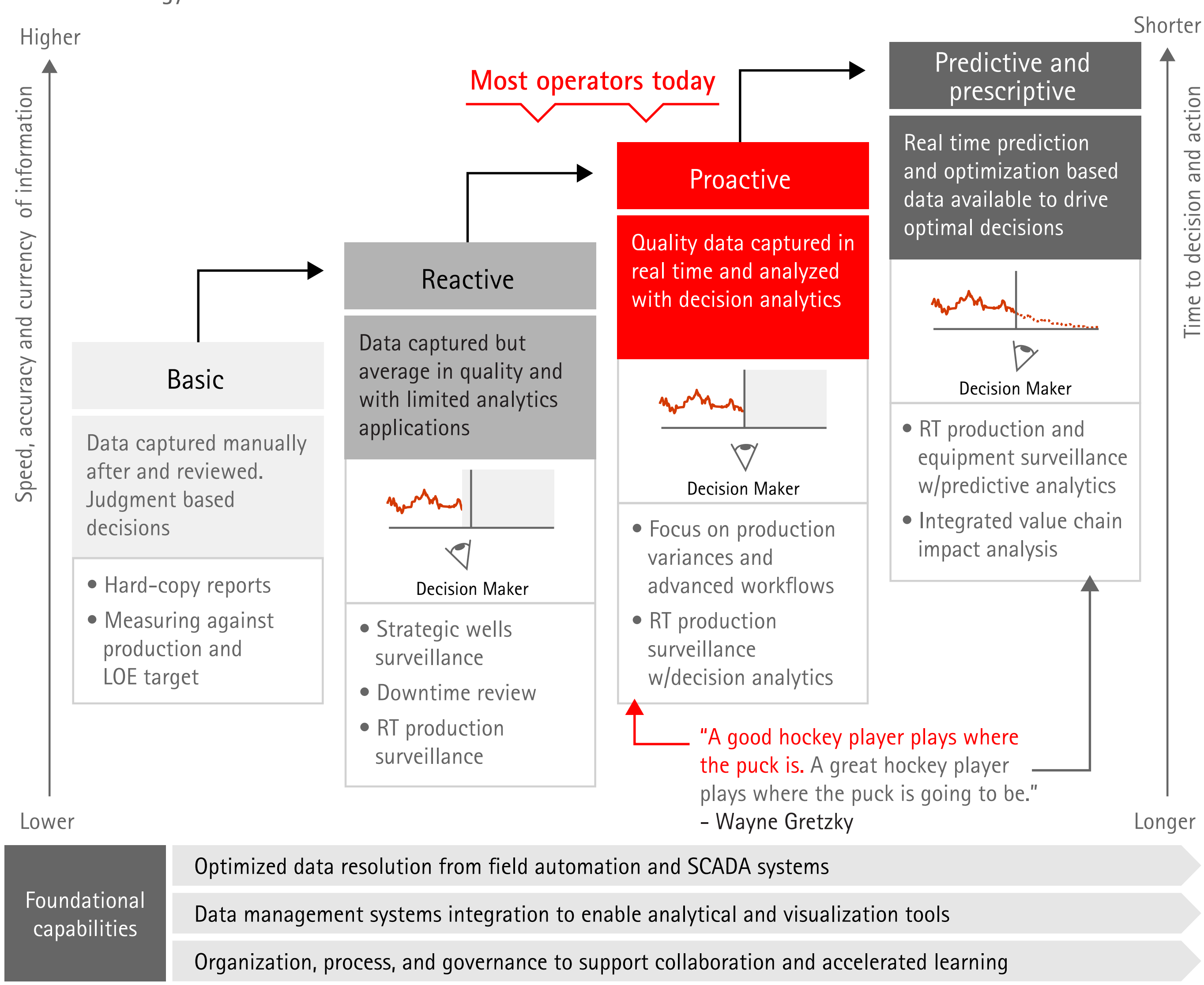
Don't wait and follow, but build an early-adopter advantage.

Oil and gas companies are still in the early stages of monetizing their treasure trove of information.

They need to step up the pace, as the new driver of competitive advantage is how quickly and effectively companies leverage technical information to maximize well lifecycle economics. In particular, predictive and prescriptive analytics (Figure 9)—in which digital technologies link exploration through to production with the help of big data-analytics—can expose the drivers behind the best-producing wells. For instance, was it where the operator decided to drill or when artificial lift was brought on line and how it was used? Digital can give operators the tools to break down each foot drilled, each stage hydraulically fractured, or each setting on the pad to identify the traits that yielded the best results—and ultimately define an ideal well.

Figure 9: Digital analytics evolution

Accenture Strategy's ICSE Framework



Many other potential scenarios make the case for digital—whether it is to better manage a fleet, optimize producing assets, improve field personnel productivity, predict equipment failures, or employ remote asset monitoring and control.

In unconventionals, for instance, real-time operations centers can materially reduce non-productive time in Drilling & Completions by analyzing in real time the more than 30,000 data variables captured on drilling rigs (of which less than 1 percent is currently analyzed). Going beyond simple correlations, advanced machine-learning can enable remote auto-drilling across multiple locations from a central control room and better help predict the sweet spot. For one operator, Drilling & Completions advanced analytics (such as ROP optimization, remote directional drilling, and screenout detection) reduced total cost by over 20 percent and increased average production and reserves by well as much as 10 percent.

On the production side, some operators have deployed real-time centers to speed decision making and reduce the need for someone to visit a well daily. The next evolution: truly embracing remote asset monitoring and control using big data analytics to predict failures and take action before failures happen; and creating workflows that automate changes (such as to a plunger lift or chemical injection rates) based on predefined variables to reduce the need for an actual engineer to review every data element to understand the issue—thus, reducing the time to intervene and maximizing production. The results can be dramatic: By leveraging digital technologies for production optimization, one operator boosted workforce productivity by 70 percent (by automating route prioritization to increase wells-to-operator ratios); slashed unplanned downtime by 50 percent (by using predictive analytics to understand when liquid loading and line pressure issues must be addressed before the well goes down); and cut road miles by 50 percent (by using analytics to assess when to visit a well).

Do not let a good crisis go to waste

By all accounts, the industry is in crisis. In fact, many operators face existential risks.

The natural instinct would be to just seek shelter until better times return. But our research shows that even if commodity prices were to shoot back up, the industry would likely find itself in the same returns- and cash flow-challenged situation it faced in the years preceding the recent downturn. Successful operators will be those that consistently stay on top of new trends, adapt rapidly, and don't wait for yet another market crisis to change.

Acting on the five imperatives just discussed can help the industry navigate one of the most challenging cycles it has ever faced—and in doing so, build a resilient model designed to succeed across cycles. By embracing these changes, operators in North America could:

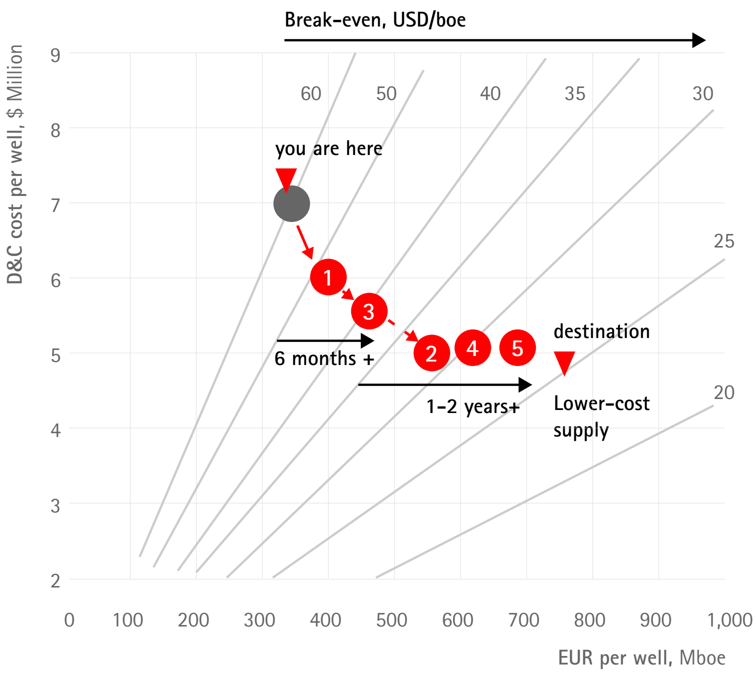
- Gain visibility into performance and cost drivers to high grade their portfolios and focus their development on the best acreage.
- Reinvigorate continuous improvement programs aimed at unit cost and well productivity.
- Test and commercialize a new working model with suppliers.
- Rethink their operating structure to ensure it aligns with their strategic aspiration.
- Redeploy talent to and invest dollars in building capabilities that include a digital and analytical backbone.

It will be well worth the effort. North American operators could dramatically improve their average break-even economics—from $50 to $60/boe to potentially as low as $25 to $35/boe (Figure 10). This will position them advantageously in a $30 to $40/barrel world and put them sustainably in the center of the global supply curve. It would generate present value of approximately $125 billion to $175 billion, which would be within striking distance of the total long-term debt ($175 billion to $200 billion) carried by North American producers.

In other words, North American operators can go from fighting extinction to becoming core producers with sustainable returns and balance sheets. They cannot afford to wait.

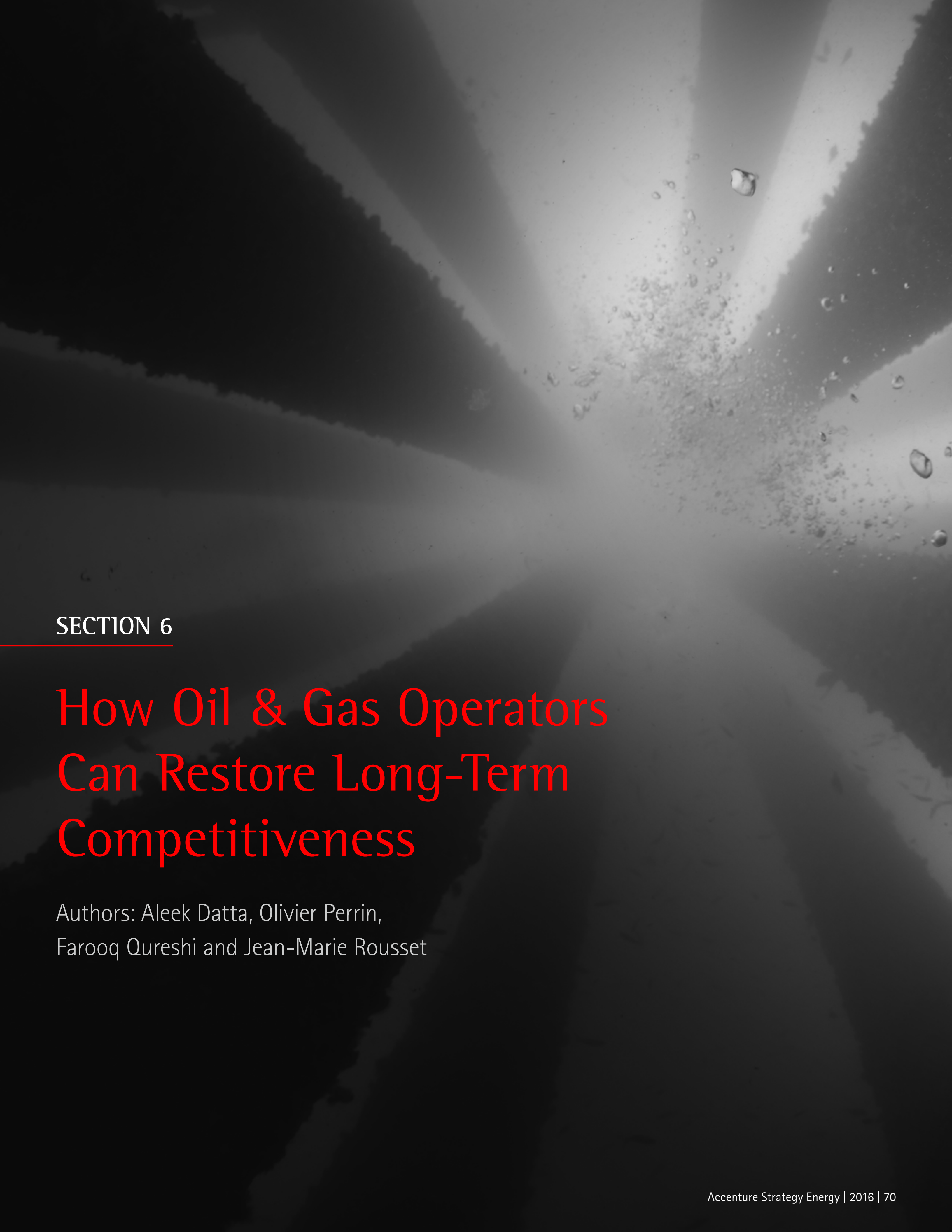
Figure 10: Value derived from the five imperatives

Potential paths to lower-cost supply



What to do and/or gain from in 2016

1. High-res. portfolio: cut or transfer out capex from marginal counties (sub $50 or $40 BE)
   Immediate impact
2. S-O coherence: conduct strategy refresh, identify non-core assets/businesses, and ensure structure/capabilities support strategy
   Key enabler
3. E^4: Optimize interventions, create collaborative work environments, and conduct activity driver based cost evaluations
   3-12 month impact
4. ICSE: Identify technologies for cost/productivity improvement and efficiency improvement initiatives with suppliers and set up a commercial model that maintains cash flow neutrality upfront
   6-12 month impact
5. Innovation, digital and analytics: set up targeted projects around equipment failure prediction, drilling optimization, and real-time surveillance
   6-12 months impact



SECTION 6

How Oil & Gas Operators Can Restore Long-Term Competitiveness

Authors: Aleek Datta, Olivier Perrin,
Farooq Qureshi and Jean-Marie Rousset

The legacy of the boom

Apart from a blip in 2009, the oil and gas industry enjoyed an extended run of growth in oil demand and a surge in prices for the better part of the past decade.

As the prospect of a relatively low-volatility, high-oil-price environment justified a more ambitious approach, many companies took the plunge into such higher-cost and complex assets as ultra-deepwater, oil sands, and Arctic. Operators recognized such activities would put pressure on their balance sheets, but they believed that in a robust oil market, delivering growth and unlocking new reserves trumped cost efficiency.

To support this focus on growth and to deal with the accompanying complexity, companies began retooling their operations. They organized activities into functional structures, consolidating scarce resources and competencies and deploying them more efficiently across the portfolio. And as the quest for growth intensified, operators reinforced the importance of corporate functions, driving more stringent governance, compliance, and globally defined capabilities.

However, the concentration of activities at the corporate level also had a downside. Companies often didn't account for differences in service levels and technical support and, thus, couldn't cater to the unique needs of each asset class. As a consequence, lines of accountability became opaque, muddying technical/economic tradeoffs and feeding the cost inflation of the past ten years. In reality, the industry was showing symptoms of the problem long before the downturn in the form of diminishing return on capital employed despite rising commodity prices.

We all know what happened next. As the oil price began to decline rapidly in mid-2014, many projects came under significant cost pressure. Operators reacted how one would expect: by announcing asset divestments, project deferrals, operating cost reductions, contract renegotiations, and personnel cuts across their functions. While the first announcements were made as early as November 2014 at an oil price of about US$80, operators took further measures as oil prices continued to drop. For instance, in 2015 alone, we saw approximately 150,000 layoffs,[1] and an additional 100,000 look possible in 2016.

However painful it has been, the first wave of cost cutting was necessary to achieve short-term reductions to counteract the oil price plunge. But that's the inherent problem with this course of action: It will do nothing to address the structural changes the industry needs to deliver long-term, sustainable cost reductions and efficiency improvements. In the face of ongoing price volatility, operators instead must carefully review their underlying operating models, organizational structures and capabilities to determine what's necessary to restore competitiveness in a lower-price, higher-volatility environment.

[1] Accenture Strategy Energy Upstream HR Benchmark Analysis determined the distribution of layoffs across oil & gas players as follows: oil-field service providers: 57 percent, EPC companies: 17 percent, Majors and Independents: each 13 percent.

Steps toward deeper, more sustainable change

A "lower for longer" oil price scenario requires more radical changes to the way a company functions. For most operators, such changes involve an overhaul of the organization structure itself and related governance, as well as steps toward building different skills and capabilities.

To create a more agile organization, some operators are separating into distinctly different businesses and, in the process, reducing organizational layers and overall staff levels. The most prominent recent example is the US unconventional market, for which several international operators have formed separate business units to handle that market's unique challenges and opportunities. These new businesses include a completely separate management team, governance, business processes, and performance reporting. Operators believe this new structure can boost the speed of innovation and decision-making, increase the senior management team's availability, reduce or eliminate corporate overhead, shorten cycle times, and enhance cost management efficiency.

Other operators are re-assessing the role and remit of the corporate center as well as related governance processes that affect decision-making quality and speed. While the discussion of asset versus functional organizations is a timeless one, today the changes are more subtle: challenging policies and standards, finessing performance management, and adjusting the level of control of crucial project decisions or risk assessments. Consider how one company, an international major, recently changed its approach to decision-making to increase accountability.

In the past, the company's assets were required to get approval from corporate or central functions first—which sometimes resulted in dispersed accountability and sub-optimal assurance. The operator decided to revise the existing decision making process by giving asset teams the authority to decide for themselves whether a planned activity is feasible, as long as the activity is in line with corporate policies. In fact, assets are now fully responsible for their own P&L and performance metrics that result from their decisions. Corporate functions' involvement has shifted to peer reviews or providing specific expertise upon request. The outcome of the change is encouraging: The operator has seen an improvement in overall investment decision accountability and quality.

Operators also are taking a critical look at their people model, enacting changes ranging from placing people where tasks are performed and fulfilling localization requirements, to building tailored people capabilities, to fostering an entrepreneurial culture. For instance, an Asian NOC has benefited substantially from establishing "real-time decision centers"—teams of people who are physically co-located in the producing assets while continuing to report to their respective functions. With NOCs typically lacking the freedom to change their portfolio, this subtle change helped the Asian NOC to bridge the corporate-asset gap, leading to more efficient and integrated execution and decision making and an overall improved business focus at the assets. The operator hopes the revised people model ultimately helps support a broader shift in mindset, from a traditional E&P view to a more cost- and profit-driven entrepreneurial culture.

In some instances, operators are creating organizational structures that better allow sharing of capabilities across similar assets and, in turn, improve competitiveness.

For instance, many North American unconventional operators have developed their technical and operational capabilities at the asset level, as integration and adaptation to regional context were critical to success. However, with the reduction in activity levels, it is difficult if not impossible for one asset to maintain high utilization of these expensive and specialized equipments or resources. Instead, these must either be shared across multiple assets or shifted quickly. Similarly, operators are increasingly focused on disseminating innovation and best practices much more quickly across asset teams, typically by creating formal or informal structures including knowledge networks (such as communities or practices), centers of excellence, and technical directions. Designing and implementing these "centralized" structures requires very careful planning to achieve the expected benefits without disrupting the asset teams' ability to operate in an integrated way (which remains a key success factor). In several instances, centralized structures are also used to help develop or accelerate the deployment of new capabilities required by asset portfolio changes—such as advanced analytics, continuous improvement, and technical innovation.

The aforementioned operating model adjustments have enhanced organizational efficiency and improved process functionality. But the work is far from done. In the next phase, the industry will need to not only review the organizational and people components of their operating model, but also rethink other elements of their business to make the longer-term shift in their cost structure. Companies will likely need to question how exploration is done, how they can involve service/engineering companies earlier in field development, and how they could reconfigure their own supply chains. Digital technologies are a key enabler of such changes. For example, they can help support remote operations in drilling and production surveillance and generate deeper insights into production trends through advanced analytics.

How to tackle the challenge

But where should operators begin? Based on our client work and a review of available oil and gas industry best practices, we see successful companies aligning their organization's operating model with their strategy—starting with reviewing the company's strategy and portfolio and agreeing on where the company is strong and in which plays and geographies it should engage.

Once they achieve consensus on their strategy, organizations then determine the right asset grouping and the appropriate organization structure, governance, people model, and capabilities to execute the strategy. A more detailed description of the approach we found in our research is illustrated in Figure 1.

Figure 1: An approach to aligning operating model to strategy

1. Review portfolio & operating model	• Review "as-is" portfolio and operating model and compare assets' performance • Identify opportunities to update strategy and/or operating model to aim for best in class
2. Adjust strategy & portfolio	• Decide adjustments to the strategy based on the opportunities identified • Clearly outline in which regions and play types to invest or divest (core, "bets", opportunistic)
3. Identify required capabilities	• Determine foundational and distinctive capabilities to deliver on the updated strategy • Define role and remit of integrated asset teams and functional support teams in relation to those capabilities
4. Define structures	• Select the most efficient and effective grouping of assets and functions • Determine governance model, providing appropriate level of control and accountability
5. Identify competency mix & staffing levels	• Determine the types (skillset/expertise) and number of resources required for each organizational construct • Analyze degree of resource sharing or outsourcing required
6. Create transition plan	• Put a robust implementation plan in place • Provide transparency in terms of action owners and deadlines

Case study

Tailoring the operating model at an oil and gas operator

One diversified operator recently embarked on such a transformation. We describe this real-world example of the operator's journey to illustrate typical issues faced, the approach taken, and the outcomes achieved.

Issues faced

The operator was suffering in the current market environment: Its financial performance and competitive situation were declining. The company had developed a diversified and geographically dispersed asset base, which it complemented with a very central organization. However, this generalization across a mix of land, shallow-water, and deep-water assets in new as well as mature basins (including enhanced oil recovery) created inefficiencies throughout the organization. For instance, the company's corporate functions couldn't deliver customized services, which led to duplicated activities across the organization. Furthermore, the operator experienced technical competency gaps and people performance issues. And possibly most important, the company lacked visibility on asset performance, so it couldn't identify the reasons behind the deteriorating financials.

Approach taken

Knowing that managing such a portfolio requires unique capabilities, competencies, and degrees of centralization to "win" in each asset class, the operator reviewed its strategy and redefined distinct business units tailored to their specific challenges. The company chose to reorganize its portfolio by segregating specific asset classes into unique business entities. Following the adage "structure follows strategy,"[2] the company refined the distinct business units to meet the asset needs. For example, for the one-of-a-kind, less capex intensive assets, the company assigned most corporate function experts to the asset teams where economically justified, leveraging external professionals otherwise. Conversely, the company established fit-for-purpose centers of excellence for a few critical disciplines (e.g. completions, data analytics) to foster innovation and sharing of best practices across a particular group of fast growing capex intensive assets (e.g. LTO).

Such moves have a dual benefit: They enable the company to address the immediate cost pressure in today's "lower for longer" environment while positioning it to grow and outperform peers in the future. The company reviewed its existing versus best-in-class capabilities and identified critical gaps with respect to its strategy and anticipated future asset portfolio. After identifying the required organizational capabilities, the company developed a transition roadmap that included required competency mix and staffing levels.[3] Finally, to achieve the benefits quickly across the organization, the company deployed specific implementation teams that applied the agreed changes in a highly disciplined and structured way while also keeping the entire organization informed of its progress.

[2] Chandler, A.D. Jr. (1962). Strategy and Structure: Chapters in the History of the American Industrial Enterprise. Cambridge, MA: MIT Press.

[3] For this task, tools such as the Accenture Strategy, Energy HR Benchmark help to assess the competency mix and staffing levels relative to operational and financial performance as well as people productivity metrics. The Accenture Strategy Energy HR Benchmark has been maintained since 2004 and has assessed the global supply and demand for petro-technical professionals and highlighted best practices in talent management. The annual survey has become the reference point for industry professionals who seek talent strategies that have impact on business results.

Outcomes achieved

Grouping assets with similar operational requirements and technical challenges helped the company to more clearly pursue its strategic objectives and tackle the unique technical challenges of each group. These and other changes enabled the organization to gain tighter control on operating costs, reduce its fixed costs, clarify P&L and operational accountability, and make faster decisions regardless of short- or long-cycle-time assets. The new structure also allows the operator to more effectively scale up or down its operations based on market conditions, which will serve as a foundation for future growth and differentiation. The assessment of staffing levels for various operations functions and associated cost indicators identified further HR-related initiatives, which will drive talent management practices and competency development to establish a more agile and nimble organization in the long-term.

Conclusion

As the oil and gas industry continues to grapple with low oil prices, the question "How low can it go?" has been replaced with "How long will this last?"

Of course, no one knows for sure, but the fact remains: The across-the-board cost cuts that companies quickly enacted when prices started to slump in mid-2014, while delivering immediate savings, will not help companies regain profitability in a US$40 (or lower) environment. The reality is that costs eventually rebound to old or even higher levels as such changes are not sustainable. For instance, a focus on headcount reduction only may shift workload to third parties, resulting in increased spend while depleting capabilities and leave operators ill-equipped to execute their strategy.

What's needed are deep structural changes that are based on identifying the root causes of high costs and organizational inefficiencies. Such changes can not only consolidate larger overall headcount adjustments—more than 30 percent in our experience, versus the 10 or 20 percent delivered through traditional headcount-reduction techniques—but also sustain the associated cost benefits far into the future. By more effectively aligning their strategy and underlying operating models, operators can build a solid foundation for long-term competitiveness that's not inextricably tied to the price of oil.

But even those changes might not be enough. Operators must be open to a complete rethinking of all aspects of their business and, perhaps more important, continually look for disruptive trends they can apply for their own benefit. For instance, taking a page or two from the book of other industries, such as aerospace or automotive, may spark ideas for how to change—or create completely new—business models. Additionally, more deeply exploiting available data, often using advanced analytics, can help operators make more informed and effective decisions.

Potential further innovations could include embracing advancements in digital oilfields, adopting continuous process improvement, or striking genuine partnerships with contractors. For example, one major is piloting "supplier-led solutions" with a strong emphasis on standardization and reusing existing concepts to fast-track development. Several other operators, having significantly reduced investments in their own R&D function in response to cost pressures, have jointly pledged funds to support a science services and solutions provider's ongoing research projects.

Operators have many possibilities before them. Capitalizing on them will require a willingness to transcend the status quo, innovative thinking, and, most of all, leaders who are ready to define a new future for the industry.

SECTION 7

The Future of Upstream Projects:

Beyond cost savings

Author: Eric Janvier

On November 5 and 6, 2015, one year after oil prices started to slide from their $100-plus peak, Accenture Strategy Energy Upstream held its fourth Capital Projects forum in London. As in previous events, executives from the oil and gas industry gathered to explore new thinking about management priorities for projects and to be inspired by other industries' experience. Unsurprisingly, the focus in 2015 was on costs: what more can operators do to restore development project profitability?

The good news: costs are coming down

Many presenters confirmed that a year-long effort to reduce project costs was beginning to bear fruit: Most analysts reported a cost reduction of 10 to 30 percent for Upstream capex in the first six months of 2015, depending on category. Some more cyclical activities such as seismics or drilling posted even steeper declines.

Most of this decline came from renegotiating terms with suppliers and delaying marginal projects. At the same time, a need for more fundamental cost cutting remains. At our 2014 forum, when the barrel was still hovering around $100, we suggested four levers were key to curbing cost inflation and developing increasingly marginal fields: specialization, standardization, lean engineering and collaboration with suppliers. Companies quickly embraced the three latter concepts when the reality of low prices became clear. These concepts also, in the course of the year, received considerable attention in many strategy statements, public communications and industry conferences.

What was new at the 2015 forum is that some companies—operators and EPCs—reported the application of some of these principles generated tangible results. Presenters made convincing cases for standardization and reuse, either at a component level—in subsea, for instance—or at the level of entire concepts—such as in the Gulf of Mexico. They also demonstrated compelling returns on deeper collaborations with selected suppliers, albeit still at a project level.

Even more interesting, game-changing initiatives from other industries were the highlight of the forum when they would have seemed only marginally relevant a few years ago. That is because participants could see a direct parallel between the motivation behind each of these cases and the challenges the Upstream industry faces today. More important, they also could envision how similar initiatives could pave the way to a quite different—and, in some way, more effective—approach to oil and gas capital projects.

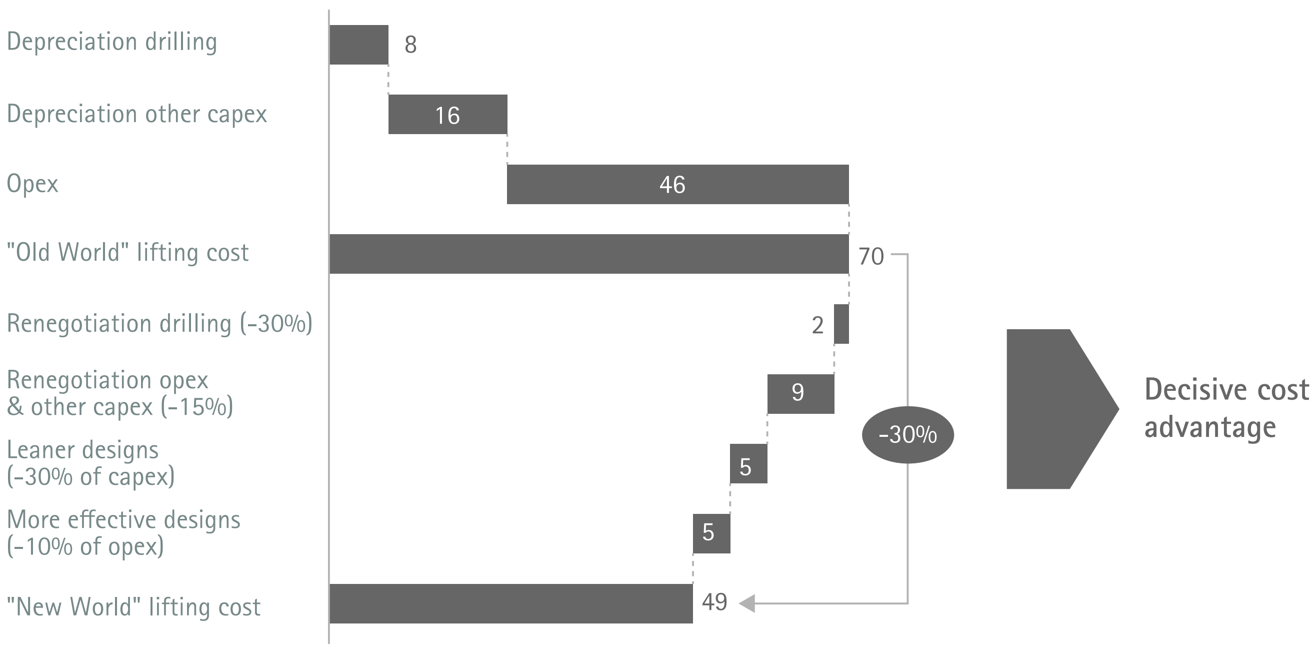
The other good news: a lot of efficiency potential is still on the table

These initial results may signal a shift in thinking in the Upstream industry. However, as effective as they have been, current efforts will not be sufficient to restore the competitiveness of conventional oil in a world of $30 to $50 per barrel. To align the costs of new projects to the current economic reality, much more is needed than simply increasing pressure on suppliers (Figure 1).

Similar dynamics were at play in the 1980s in the North Sea with CRINE and in 2008 during the recession. In both cases, the industry undertook efforts as it does now, only to revert to traditional practices once the skies started to clear. Forcing suppliers to forfeit their margins and slash costs also has limits because the industry's performance depends on the supply chain's capabilities and reliability. After a year of activity decline, pressure on prices and heavy cost cutting, the industry is reaching these limits. High-performance drilling rigs are scrapped in the yards, entire seismic acquisition fleets are decommissioned, tens of thousands of experienced engineers whose scarcity was lamented until two years ago are made redundant, and leading suppliers are struggling to survive.

With oil prices flirting with $30, our industry needs to enact deeper structural changes—to "go after the 90 percent of project costs, rather than the 10 percent margins of our suppliers" as one forum participant put it. The good news is that significant potential exists for the more daring to capture, as demonstrated by some forum presenters.

Figure 1: Impact of capex and opex reduction efforts on lifting costs, in a typical offshore development (USD/bbl)



Source: Accenture Strategy, Energy

Thames Water, for instance, presented its Eight2O alliance with six key suppliers[1] to deliver its five-year work program. BoostAerospace[2] discussed the aerospace collaboration platform that brings together nearly 2,000 clients and suppliers of the European aerospace industry. Rolls-Royce made a case for lean engineering, continuous improvement and collaboration with suppliers. And the UK Major Projects Authority[3] reviewed its activities, including the requirement in 2016 for all UK public civil works projects exceeding £50 million to be integrated on a single Building Information Management (BIM) system[4]. EPC participants also highlighted the potential benefits from deeper collaboration with clients and integrated data management platforms.

A few years ago, these presentations would have been met with polite interest by Upstream practitioners. This year, they served as a stark illustration of the gap that remains to be closed.

In Upstream, reuse and standardization are only beginning: Developing two comparable offshore fields with the same design base is too seldom the consequence of purposeful growth and engineering strategies. Many operators still insist on maintaining their own proprietary specifications for valves, or to impose their own technical standards for railings, ladders, or cranes. According to DNV-GL, specifications for a typical subsea project have grown sevenfold in the past three years: from 15,000 man-hours in 2012 to 120,000 today, with each of the 120,000 documents being revised an average of three times.

Similarly, collaboration with suppliers is on many operators' agendas. But it is still often limited to the scope of a single project—unlike many other industries, which focus on the benefits of long-term collaborations.

Upstream information systems are similarly lagging. Document management remains a hot topic in our industry, with each revision of changes often taking more than two weeks when it is not lost. In contrast, Airbus has 2,000 suppliers working concurrently on a single digital mock-up of the airplane, updated at the end of each week; and large European aerospace companies and tier-one contractors jointly developed BoostAerospace, a collaboration and supply chain management platform that integrates nearly 2,000 clients and suppliers. Scanning technologies to create 3D models of installations is a fast-growing market in Upstream, when other industries simply inherit the 3D models and corresponding technical data directly from the design models.

Non-oil and gas industries adopted these changes five to 20 years ago, when they confronted challenges similar to those our industry now faces. It took a few visionaries, a lot of persistence and the courage to change company cultures. We believe it is time for a few companies in oil and gas to do the same.

[1] www.thameswater.co.uk/about-us/17410.htm
[2] www.boostaerospace.com/
[3] www.gov.uk/government/groups/major-projects-authority
[4] www.gov.uk/government/uploads/system/uploads/attachment_data/file/34710/12-1327-building-information-modelling.pdf

So where do we go from here?

It is certainly possible for the industry to emulate what happened in 2008: Oil prices rebounded and companies reverted to the unchecked growth and inflation that characterized the past 10 years.

However, even if the oil prices rebound, the pressure will remain. Unless we change our approach to capital projects, conventional resources will continue to become increasingly more marginal, while unconventionals and alternative energies will increase their cost advantage and continue to gain market share.

If, however, enough players decide to pick up the gauntlet and embark on a full transformation, how would that impact the industry? We believe it would lead to changes quite similar to what we saw in aerospace 10 years ago and in automotive 20 years ago: deeper and longer-lasting collaboration with key suppliers, leading to the emergence of supply chain ecosystems built around a couple of majors and EPCs who together impose new sets of cost and performance benchmarks, at least for specific categories of projects.

The value of such collaborative ecosystems is evident in industries where they function: They allow more effective working practices supported by more integrated systems; they facilitate the development and fabrication of solutions and concepts that can be reused and improved over time; and they encourage joint continuous improvement over longer horizons than a single project, thus boosting performance and lowering costs. Companies that get ecosystems to work capture huge benefits, as shown in industries such as aerospace, automotive, heavy equipment and utilities.

But while ecosystems make sense conceptually, they inevitably raise a host of challenges. One of the biggest is the culture change required to foster and support deep collaboration. Interests are hard to align. It is difficult to devise a mechanism to share value between a client and a supplier that both parties consistently perceive as fair. Long-term commitments are prone to withering in the face of uncertainty. Mutual trust takes a long time to build and can be destroyed in an instant. And all suppliers will have limited capabilities, and all their teams will not be “the A team.” Yet those issues can be addressed. Companies in other industries have faced the same challenges, figured how to make ecosystems work and now enjoy levels of project performance that would seem unattainable to the Upstream industry.

A fascinating analysis of this journey in the automotive industry was written by Susan Helper, an economist at Case Western Reserve University[5]. The automotive industry had the advantage of the example set by Toyota and Honda, which provided an alternative to what Helper calls the “exit” procurement strategy. The aerospace industry came to similar conclusions. As one aerospace executive participating in our forum explained it during our preparatory discussions:

“In Aerospace, we discovered that it is so hard to find suppliers that have the right certifications and bring the capabilities that match our requirements, that when we find them, we want to keep them and to help them improve; the last thing we want is to switch them!”.

[5] Susan Helper & John Paul MacDuffie « Collaboration in Supply Chains, With and Without Trust
http://faculty.weatherhead.case.edu/susan-helper/publications/

How to make change happen

We believe the Upstream industry is at the beginning of a similar journey. This means there is an opportunity for a select few to take the lead and claim a durable competitive advantage.

The questions are, who could be such a "first mover" and how could that company make it happen?

A look across industries suggests that any company can choose to encourage more or less collaboration with its suppliers. Some Upstream players, however, will find they are better positioned to implement the full suite of changes—standardization, lean engineering, and collaboration—and derive the greater value. At a minimum, a company would facilitate the development of lean standards, push the reuse of components and proven designs, identify capable suppliers, and develop effective collaboration practices and systems. Mutual trust will also be facilitated if both the client and the suppliers have a robust experience with the developments in scope, and if the suppliers are motivated by the possibility of repeat business. The natural candidate, therefore, will be either a major that can leverage the size of its portfolio and carve a suitable portion from it, or a "specialized" independent that enjoys a similar scale advantage despite its smaller size. The major would probably benefit from its extensive staffing capacity and its greater negotiating power, but the specialist would benefit from shorter management lines and superior flexibility.

The first task for this operator would be to confirm which portion of its project pipeline is best suited for the exercise. A large gas specialist could select LNG plants, or FLNGs; an offshore operator could choose semi-subs, subsea installations and a range of water depth in the Gulf of Mexico; and an onshore operator could opt for its light tight oil operations in US land.

The operator would then select one or two of its most trusted EPCs, and the top leadership from all companies would agree on their commitment to the long-term vision: building a common supply chain ecosystem that will boost performance across the segment in the next 10 years. The operator might also evaluate if it makes sense to recruit one or two other operators facing similar development challenges to increase the size of the pie.

From there, this team of "founding members" would jointly define the nascent ecosystem' principles, components and supporting platform: the shared philosophy and the governance model; the client-supplier engagement models; and the collaboration and coordination systems.

They would then engage with the broader supplier community to jointly work toward a common framework for technical standards, libraries of standard modules and concepts, certification and quality assurance guidelines, and a continuous improvement philosophy. As the work progresses and the activity develops, new suppliers would be qualified to join the ecosystem and leverage its collaboration mechanisms.

Many industry groups and independent parties are currently working on some of these issues. What we propose, however, is different. It is competitive, performance driven and proven in the real world.

During the definition phase, a number of questions will need to be addressed: How can we reconcile long-term engagement with activity unpredictability? How will members of the same ecosystem compete with each other and how can we comply with competition regulations? How can such an ecosystem satisfy local content requirements? How will the collaboration IT platforms interface with the systems of each ecosystem member? What is the bigger picture—the "end-game" for the eco-system—and what role will each of the participants play in its development?

Many of these questions are used to excuse current E&P practices. But most of them have also been faced in other industries that started a similar process 10 or 20 years ago, and found workable answers. Each of these other industries have their unique characteristics. But the challenges, the potential pitfalls and the opportunities for value creation are remarkably comparable, and much can be gained by studying their experience. In fact, by understanding what has happened to those industries that are one or two decades ahead of ours, we can imagine what the oil and gas industry could look like.

Operators would gradually focus on a narrower and more stable base of suppliers (such as key aerospace companies do, as illustrated in Figure 2). Clients would therefore be able to dedicate more resources to help these select suppliers strengthen their capabilities and to work on improving the joint performance. Suppliers, in turn, could co-invest in more repeatable solutions to drive costs down and boost performance. Eventually, the performance gap would increase between suppliers benefitting an ecosystem and others—leaving fewer, bigger and, importantly for their clients, more capable suppliers.

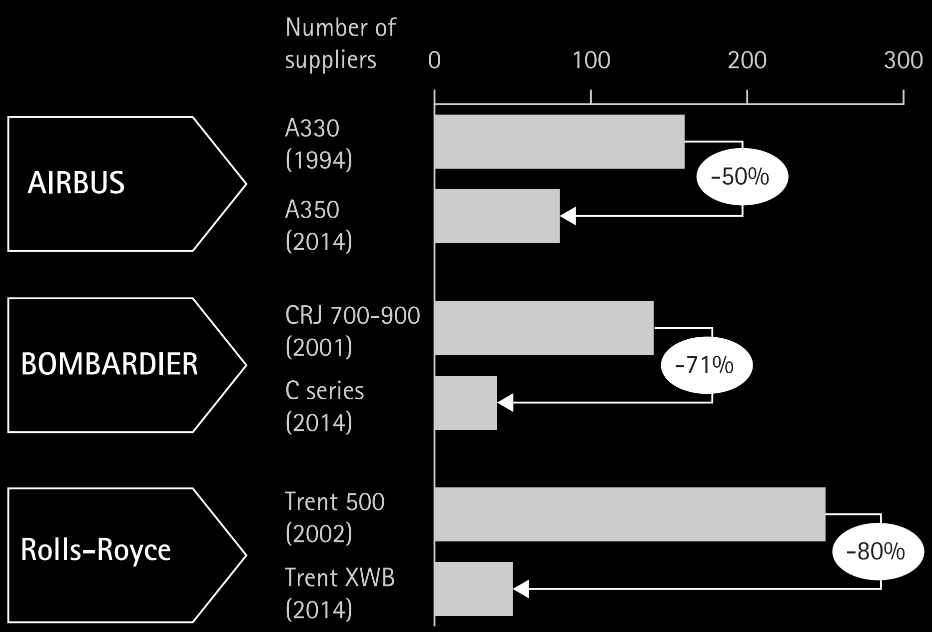
Simultaneously, first-mover operators would develop decisive cost and performance advantages in a segment of their portfolio. Based on the experience of other industries, those advantages, for equivalent developments, could reach 50 percent less capex, 20 percent lower lifting costs, 50 percent faster time to first oil, and a five-year lead time on new technology implementation. Operators enjoying such advantages would be tempted to grow their corresponding business and gain market share. Slower-moving mid-size players would join these ecosystems to benefit from the supply chain's performance. Four or five ecosystems eventually would emerge and claim a sizeable share of the market.

Whether deliberately or not, some companies are already experimenting with the early stages of these concepts. Shell, for instance, has teamed up with Technip and Samsung to design, construct and install multiple floating liquefied natural gas (FLNG) facilities for the next 10 years (Figure 3), planning to enjoy the benefits of standard solutions and a supply chain ecosystem as just described.

Another example is Anadarko, which has chosen to work intensively with FMC and Technip on a segment of its offshore developments.

The questions that remain are how fast will the lessons be learned, and how aggressively a few players will pursue this strategy.

Figure 2: Supplier concentration in the aerospace industry



Source: Accenture Strategy, Energy

It's time to challenge the traditional approach to projects

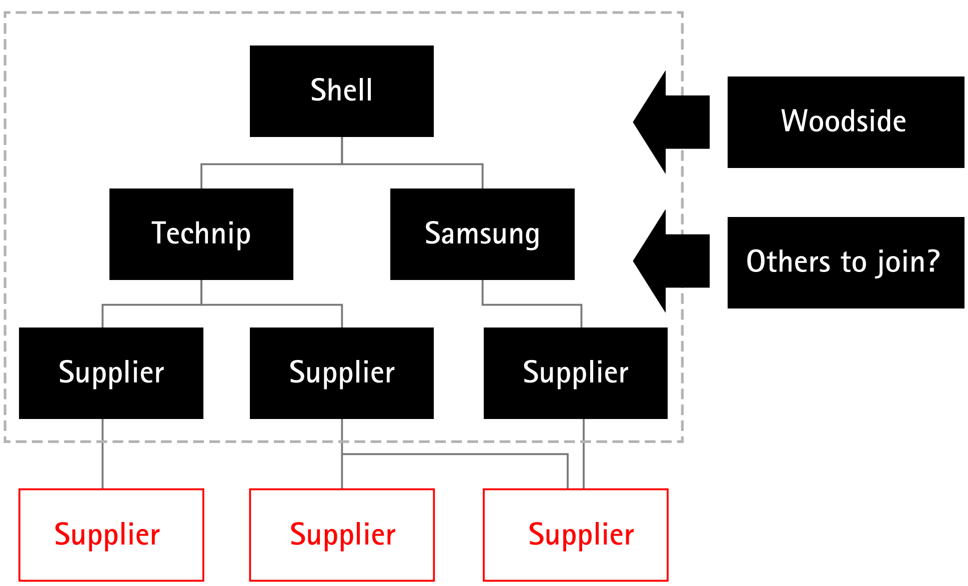
For the foreseeable future, intense pressure to reduce project and extraction costs will remain. The oil-price slide marches on and, even if prices return to higher levels, oil and gas extraction will remain increasingly challenged as reserves become more marginal.

The Upstream industry must see the current situation for what it really is: not a temporary storm to wait out, but a strong call to make structural and sustainable changes to how they approach development projects.

As the experience from the automotive, aerospace, utilities, and other sectors show, the players that get these strategies right first enjoy substantial and durable competitive benefits—much like the Japanese automotive players have done for nearly 20 years.

The challenge for companies keen to lead the pack is to quickly move from concepts and early experiments to establishing a clear vision of where they want to go and how to get there. The companies that are left standing will find themselves marginalized. They will lose their ability to compete in the large-project space and will be forced into a niche that doesn't require development efficiency. For operators that want to move, the current period may be a one-time opportunity to launch such a transformation. In the next two years, project executives should have more bandwidth and suppliers should be more open to discussions than in the past decade. When activity resumes, it probably will be too late.

Figure 3: Collaboration structure for Shell's FLNG project



Source: Accenture Strategy, Energy

SECTION 8

Five Essentials for Improving Operating Costs

Authors: Jean Cristofari, Timi Familusi,
Olivier Perrin and Jerôme Sevin

Oil and gas companies must abandon traditional cost-cutting responses to adverse market conditions and work collaboratively with suppliers to manage costs and protect margins. Accenture Strategy believes that, by following five courses of action, the industry can drastically improve its cost-management practices and, by extension, operational sustainability. Companies that fail to adapt to changing market circumstances, meanwhile, risk destroying value and becoming uncompetitive.

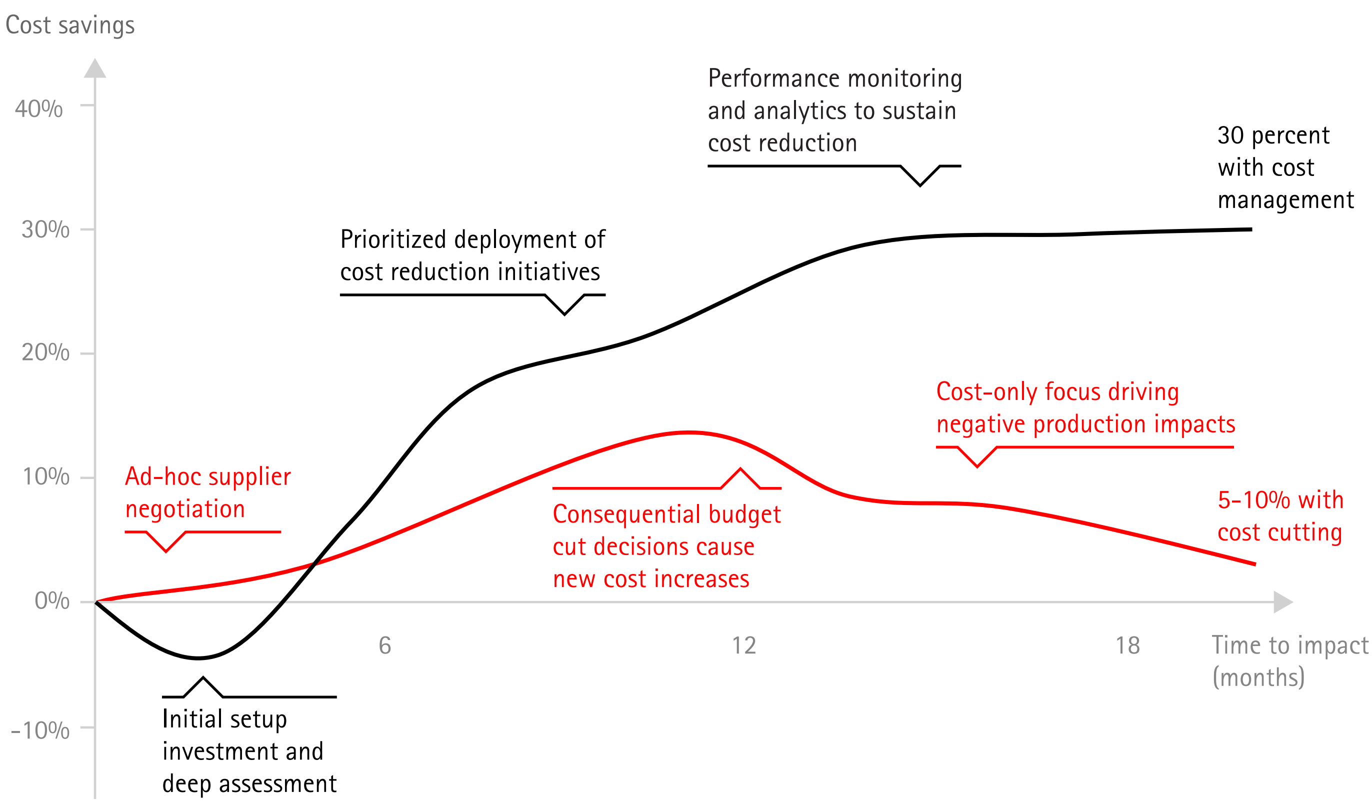
Development and production costs have more than doubled in the past 10 years and managing resources efficiently has become an ever-greater priority—especially since oil prices are likely to remain depressed for the foreseeable future. Traditionally, companies have responded to low oil prices, high costs and weak margins by cancelling or postponing projects, laying off staff and freezing spending. But, reactive short-term actions such as these, risk destroying value. Facilities maintenance, for example, often falls victim to short-term cost reductions. While slashing maintenance budgets might deliver savings in the short term, postponing maintenance will eventually undermine longer-term asset integrity, and give rise to reliability and HSE issues. In fact, many of the E&P industry's major accidents have occurred during periods characterized by extreme cost-cutting measures.

Accenture Strategy believes that cost management should not be viewed as a one-time initiative to be undertaken in reaction to adverse economic conditions. Indeed, transformational changes to the existing approach to cost management have become essential: the industry must change how it identifies the causes of inefficiencies and manages costs, and must learn to do more with less.

Accenture Strategy proposes five actions to manage costs effectively and deliver sustainable business improvements:

1. Think margin, not just production;
2. Scrutinize costs, and focus on controlling their drivers;
3. Concentrate on improving baseline production;
4. Share risks and rewards with suppliers;
5. Change culture: place greater emphasis on planning, accountability and service quality.

Figure 1: Cost management versus cost cutting



Source: Accenture Strategy, Energy analysis

Essential 1: Think margin, not just production

Increasing production is pointless if the incremental output is unprofitable.

In our experience, operators do not always have a good grasp of the cost of incremental production. Achieving maximum production from an asset is not always the most economically viable option.

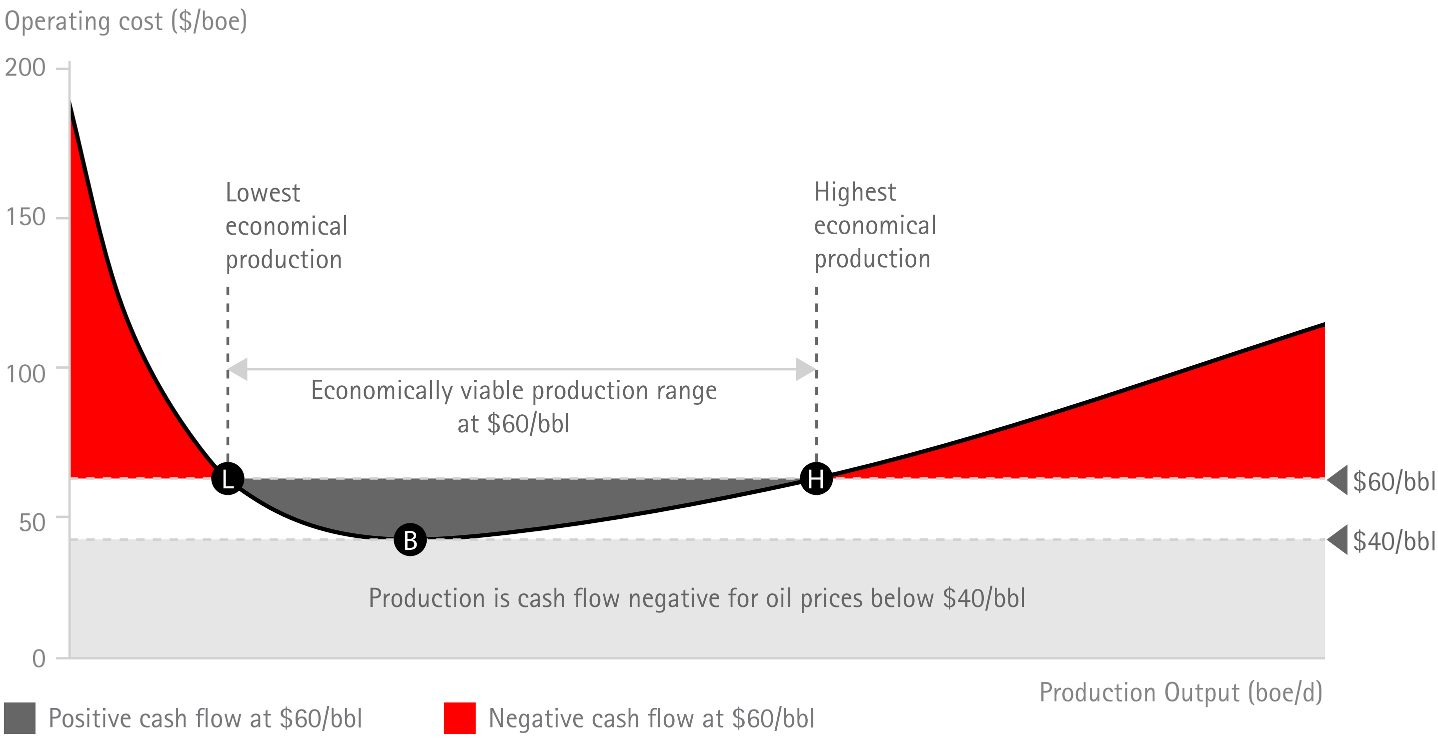
Companies need a detailed understanding of the fiscal terms of their contractual operating agreements, in terms of production sharing, tax regimes and cost-recovery mechanisms. A company can then determine its economically viable (profitable) production range, based on expected revenues, associated costs and resulting cash flows.

The economically viable production range is defined as production for which net operating cash flow is positive, as reflected by the dark gray zone in Figure 2.

For each production scenario, associated operating costs are calculated for activities designed to increase production, such as drilling additional wells or conducting artificial-lift operations. As shown in Figure 2, the operating cost curve initially decreases as fixed costs are amortized over larger production volumes (X-axis). The cost curve reaches an inflection point (point B) and thereafter begins to increase as more production is added. In this example:

- Point H is the highest economic production for a given oil price of $60/bbl;
- Point B is the lowest break-even price, reached in this case at $40/bbl;
- Point L is the lowest economic production for an oil price of $60/bbl.

Figure 2: Operating cost curve for production scenario A for an oil price at $60/bbl



Note: "Profitable" volume growth help companies focus their efforts on the right assets. This might mean "shrink" now to "grow" later when conditions become more favorable. In plays where conditions may prevent a restart at a later state, the decision is whether to continue operating uneconomically and if so, for how long.

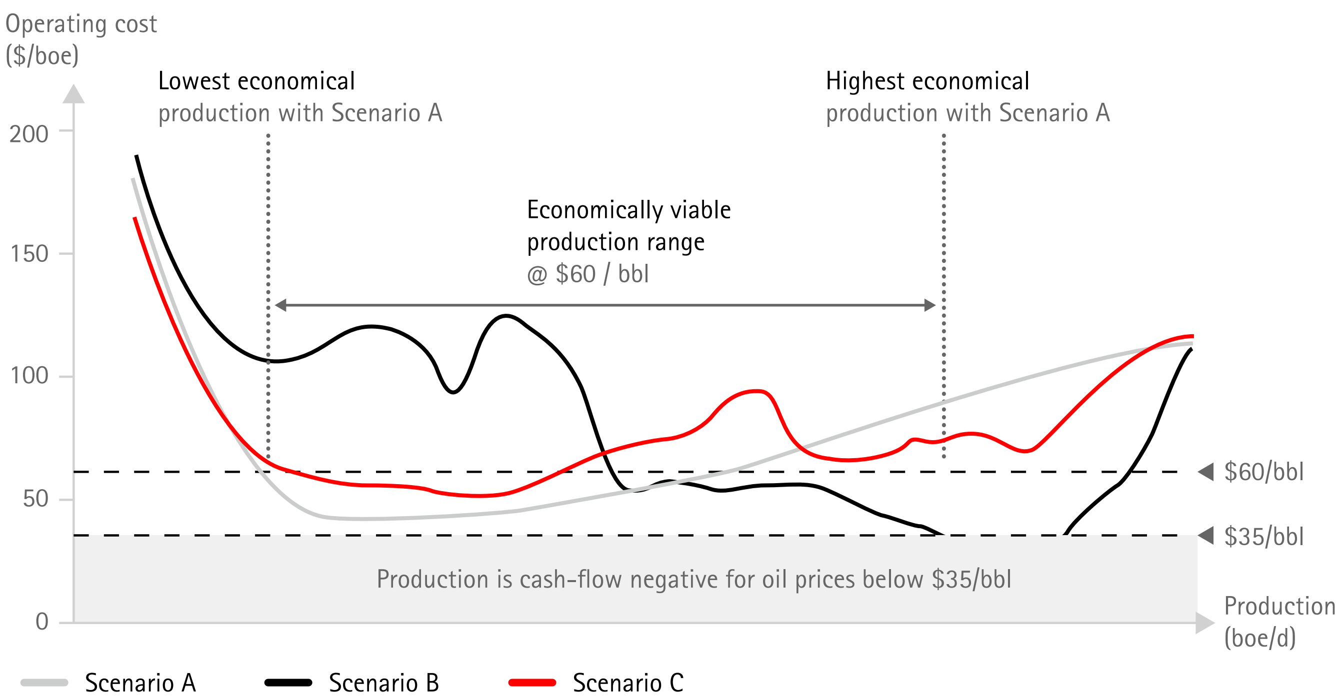
Source: Accenture Strategy, Energy analysis

Cost and production curves can be generated for multiple production scenarios, with the objective of determining optimal production levels at a given oil price (Figure 3).

Deliberately prioritizing profitable volume growth obliges companies to focus their efforts on the best assets and ensure they do not waste valuable resources developing unprofitable ones. In some cases, this might even mean temporarily shutting in some production in order to establish conditions for faster growth when market conditions improve. In plays where operational conditions may prevent a restart of curtailed production at a later date, a decision must be taken concerning whether uneconomic operations should be maintained and, if so, for how long.

Systematically developing cost and production curves also helps set clear objectives, such as an achievable cost target along the cost curve. This approach enables alignment between stakeholders to deliver on agreed cost-reduction targets.

Figure 3: Operating cost curves for different production scenarios at $60/bbl



Source: Accenture Strategy, Energy analysis

Essential 2: Scrutinize costs, and focus on controlling their drivers

The first step in achieving sustainable cost reductions is for the company to improve its understanding of its costs and their drivers.

Cost buckets should be rigorously deconstructed so that the fundamental drivers of each cost item can be analyzed effectively and operators can determine the extent to which each driver can be controlled. There are typically five levers for managing cost drivers, each providing varying degrees of control:

Raise the approval level for expensive, non-recurrent costs, in order to encourage managers to spend sufficient time preparing a business-case justification before asking their superiors for approval. Though effective in the short term, care must be taken not to burden managers with the bureaucracy of the approval process or stifle their autonomy, curtailing their ability to make quick operational decisions.

Reduce usage volume and/or frequency in some cases, reducing the quantity of consumables or usage frequency can generate substantial benefits. For example, reducing the volume of chemicals injected to treat wells or optimizing vessel utilization to reduce frequency of trips can deliver opex savings.

Renegotiate contractual terms: This tactic is common during downturns and suppliers often agree to price reductions as activity levels drop. However, as with the first lever, contract renegotiations alone do not necessarily result in sustainable long-term cost reductions. Indeed, price renegotiations can be damaging if gaining a one-off advantage damages the next transaction (this is covered further in Essential No 4).

Ensure an effective cost-control mechanism and transactional processes. This is essential for controlling operating costs. In many companies, it is very laborious to establish a clear and effective link between cost drivers and impact on the bottom line. This is mainly because of the complexity of financial reporting structures and transactional processes. Therefore, departments such as Contracts and Procurement, HR and Finance tend to be overstaffed and inefficient. These inefficiencies waste large amounts of money.

Do it differently. This is the most effective lever with the most sustainable results, but it is also the most difficult to implement. New technologies and greater standardization have provided opportunities to do things differently and in a more cost-effective manner.

The development and adoption of new technology has helped sustain growth in the E&P industry. Ultra-deep water and shale production were unthinkable 30 years ago. A recent survey of oil and gas operators by Cisco indicated that 25-50 percent of manual processes have the potential to be automated.

Some North Sea operators have set up remote drilling centers to reduce the cost of personnel on board (POB) and perform real-time monitoring of well operations. But, for the most part, the industry has been slow to adopt new technology. For example, real-time data monitoring of rotating equipment has been around for over a decade but has still not been widely adopted.

Furthermore, greater standardization of processes and solutions is required to generate economies of scale. Operators should maintain tighter control of innovation, avoid overly complex designs and focus on simpler, leaner solutions. Also, reusing designs or elements of designs that have been proved in previous projects should be encouraged rather than rebuilding from scratch, which is often unnecessarily costly and time consuming.

A case study (Figure 1) illustrates how Accenture Strategy successfully supported an operator to manage costs associated with its offshore supply vessels, using the five levers described above. The project resulted in $6MM of annualized opex savings:

Raise the approval level: all emergency requests (those raised with 48 hours of notice or less) to require a written exemption from the Head of Operations before they can be processed.

Renegotiate contract terms: fragmented transactional contracts were consolidated into a single master-frame agreement at a lower price (some contracts had been agreed during price peaks).

Reduce usage frequency: the travel-logistics schedule was revised, with a reduction in daily trips to each asset achieved by combining trips to asset locations in close proximity to each other.

Ensure an effective cost control mechanism: An initiative was launched to revamp the cost-control system completely, and, in parallel, a cost-control tool was developed to monitor costs to operations awaiting the new mechanism to be put in place.

Do it differently: Stronger demand planning helped optimize logistics resources. A control tower was created to consolidate all logistics requests from offshore assets, allocate resources and track performance. Within six months, emergency requests dropped from 50 to 10 percent. Through better visibility, the control tower was also able to streamline vessel routes, reducing total distance covered by 20 percent and reducing the marine fleet by one vessel.

Performance metrics were put in place to track vessel utilization (e.g., deck space, occupied seats) and logistics planning KPIs were included for each Asset Head.

Figure 1: Example of cost register for vessel expenditures

				Increasing sustainability			
Cost parameters				**Cost levers**			
Cost line	Drivers	Weight	Controllable	Approval level	Contractual terms	Volume or frequency	Doing it differently
Vessels	Spot requests	10%	100%	✓			
	Rental price	30%	50%		✓		
	Number of trips	30%	100%			✓	
	Logistics control tower	25%	100%				✓
	Speed limitation	5%	100%				✓

Source: Accenture Strategy, Energy analysis

Essential 3: Concentrate on improving baseline production

A recent report by BP indicated that nearly half of all the oil to be found within the next 40 years will come from already identified accumulations, since reservoirs release just a fraction of the hydrocarbons buried underground. This should be a wake-up call for companies, encouraging them to look more closely at their existing portfolio of assets and to become more efficient at oilfield management, squeezing out more resources for less money. To identify potential opportunities, companies will have to undertake a diagnostic review of existing wells and surface facilities.

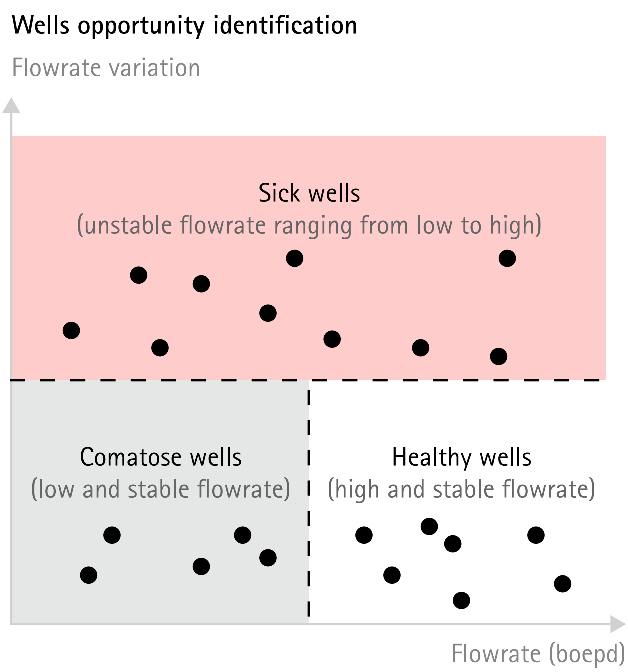
Existing wells can be classified into three categories, based on flowrate variations:

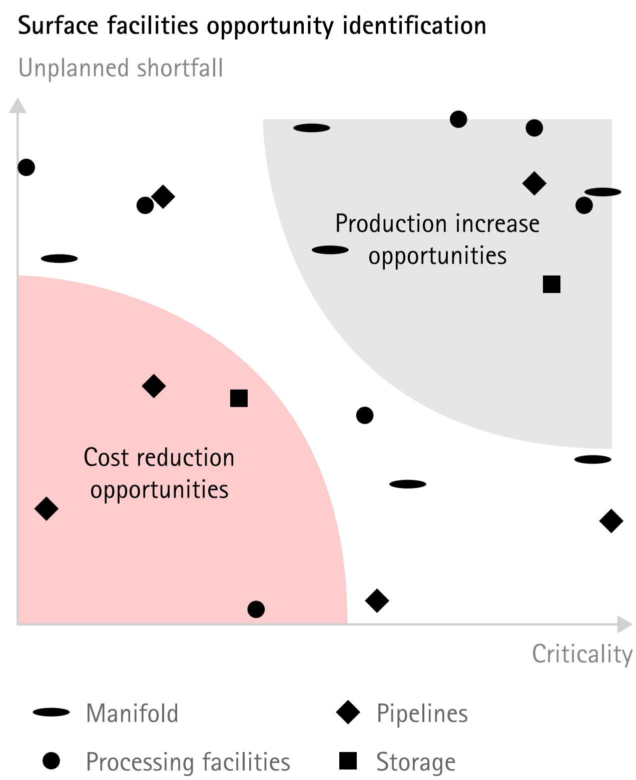
Healthy wells with high and stable flowrates.
These wells require minimal surveillance and this can be automated and done remotely to reduce staffing requirements;

Sick wells with unstable, wide variations in flowrate.
These represent the biggest opportunity for production increases. They are the best candidates for real-time remote monitoring to quickly detect production problems and launch remedial actions. In the medium term, wells with these types of production challenges need to be grouped together and studied collectively to improve operators' understanding of downhole conditions that can boost productivity;

Comatose wells with low and stable flowrates.
These wells represent either a cost-reduction opportunity, if no action is taken, or a production-increase opportunity through a heavy intervention (e.g., workover, perforation) designed to change the well's production configuration. Selecting the type of intervention would first require an economic business case for the activity in question.

Figure 4: Examples of opportunity identification for wells and surface facilities





Source: Accenture Strategy, Energy analysis

Opportunities for increasing production from surface facilities can be identified by combining unplanned shortfalls with a criticality analysis (Figure 4). Some examples of production-increase opportunities (top right hand of graph) from surface facilities include:

- Real-time monitoring of critical assets to detect anomalies early and implement mitigation plans;
- Reviewing preventive maintenance schedules to reduce the number of failures and increase equipment availability (Mean Time between failures versus Mean Time Between Preventive Maintenance);
- Reducing mean time to repair critical assets by stocking more spare parts in the warehouse.

Essential 4: Share risks and rewards with suppliers

With oil prices low by recent historical standards, operators are pressing suppliers for discounts and price cuts.

However, indiscriminately squeezing supplier margins encourages suppliers to cut corners and engage in risky or unsafe work practices, sacrificing quality in an attempt to save their own costs and preserve margins. Short-term cost savings from supplier discounts are eventually eroded by the cost of re-work, budget overruns, project delays and reliability issues in low-quality jobs. In any case, cost savings arising from supplier discounts are likely to have a minimal impact in terms of offsetting the huge revenue loss that has resulted from the ~50 percent oil price drop since June 2014.

It is time to think differently; long-term success requires changes in the behavior both of operators and suppliers. Instead of simply seeking price cuts from suppliers, oil and gas companies should attempt to collaborate more closely with their suppliers and create a mutually beneficial relationship that creates value and eliminates waste.

We see three critical levers for achieving this objective:

Defining appropriate incentives to share gains or losses

At present, supplier contracts seldom incentivize contractors to focus on improving efficiency. They are usually lump-sum contracts won by the lowest bidder. SBC's capital projects survey revealed that over 60 percent of contracts still use the "three bids and a buy" contracting model.

This is particularly true for drilling contractors, some of whom are paid by the day, almost regardless of progress. Incentives for working faster are virtually non-existent. Consequently, many service providers remain within their own domain and do not consider the full effect of their actions or inactions on the overall work flow.

The principal-agent dilemma arises because sometimes the agent (supplier) is able to make decisions on behalf of, or that impact, the principal (operator); if the incentives of the two parties are not aligned, the agent is motivated to act in his own best interests rather than those of the principal.

The goal therefore should be to reduce information asymmetry and manage conflicts of interests between operators and suppliers.

Figure 5: Tips for resolving Operator-Supplier "Principal - Agent" dilemma

Principal – Agent Considerations	Operator	Supplier
Reduce asymmetry of information	**Improve information exchange** to help supplier design the best bid **Share data for planning, scope management, standardization** (e.g. Project funnel, Engineering data, Performance data, Standards and processes)	**Seek early involvement** in operator's work program or design efforts **Improve upfront demand planning** to ensure timely delivery of goods/service **Avoid re-inventing the wheel and gold plating** (e.g. use standardization and modular designs for multiple jobs)
Manage conflicts of interest	**Define and align incentive schemes** Performance gates, Incentive for gain/pain share **Reduce supplier selection time** Seek opportunities for Framework Agreements/ standardised work packages (where appropriate) Focus negotiations only on critical issues	**Increase transparency** on cost structure and pricing for better alignment of incentives Conduct joint **R&D efforts** and initiatives

Defining the right contracting model can deliver value both for operators and suppliers. Under appropriate conditions, new collaborative working models (such as long-term frame agreements) can result in a win-win outcome. However, such contracting models only make sense if they create value for operators and incentivize suppliers.

Potential sources of value for operators include: reduced variability in performance through standardization; systematic application of lessons learned; and efficiency savings from common working methods and jointly developed work packages. Suppliers, meanwhile, can benefit from the certainty in revenue that long-term partnerships provide and the reduced cost of tendering repeatedly for the same type of work.

Collaborative operator-supplier contracting models can deliver huge benefits if properly implemented. As an example, an operator recently executed five development projects over a period of eight years, working with the same suppliers. The arrangement yielded a 60 percent reduction in costs and a 50 percent reduction in construction time between the first and the fifth development.

We have observed a slow migration towards greater collaboration between operators and suppliers within the industry. Shell and WorleyParsons signed a global agreement in 2013, with a five-year renewal option, covering engineering, procurement, and construction services for surface facilities projects in unconventional oil and gas assets. BP and Aker Solutions also signed a two-year agreement in 2013, with a four-year renewal option, covering engineering, modifications, and maintenance services for BP-operated oil and gas fields in offshore Norway. We believe these types of working agreements should be encouraged.

Forming joint working groups to achieve efficiency and cost targets

Operators need to work more closely with their suppliers to achieve production-cost optimization targets and resolve operational challenges. For example, Accenture Strategy's analysis of an operator's fracking activity in North America indicated potential for a 200 percent improvement by boosting productivity and reducing unproductive and non-job time.

To improve performance, operators and services companies can form Joint Efficiency Teams (JETs). The JET can carry out an end-to-end assessment of efficiency opportunities, from planning through execution, and start the process of implementing the actions necessary to achieve an improvement in performance. A governance body, with representation from both parties, should periodically review JET activities, based on agreed performance-evaluation criteria.

Services providers often have greater experience than operators in specific areas and niches of the E&P value chain. A JET would ensure lessons and best practices are captured, and the right behaviors reinforced in both the operator and supplier organizations.

Similar transitions have occurred in other industries, such as aircraft manufacturing. Engine manufacturers no longer just sell engines and spare parts, but also monitor the engine's performance over its lifetime to better understand its operating conditions and help airlines reduce downtime, thus improving asset productivity. A similar approach can be applied in the oil and gas industry.

Supplier tiering

Other industries have achieved better integration with their suppliers through tiering. The automotive, aerospace, and electronics industries have all restructured around original equipment manufacturers (OEMs) and tier-1 (primary) suppliers across their value chains. These three industries share some common trends in terms of (1) early involvement of suppliers in product design; (2) joint R&D efforts and initiatives between OEMs and suppliers; and (3) more risk and reward sharing between system integrators and OEMs.

As in these industries, the oil and gas supplier market can also tier itself around the main activities of its value chain. Tier 1 suppliers can consolidate around field development, well delivery, engineering and construction, and field management, while clusters of Tier 2 OEMs work together to support the primary Tier-1 services providers.

Today, operators sometimes have to deal with as many as 15 different suppliers and OEMs during production operations. These can create numerous problems in terms of equipment compatibility and costly, complex inventory-management systems. Supplier tiering would help resolve some of those problems. The number of automotive industry suppliers, for example, has fallen by 80 percent over the past three decades, yet the size of the supplier market has increased six-fold in value over that time.

Essential 5: Change culture

Place greater emphasis on planning, accountability and service quality.

Operators need to change their operating model to reinforce cost consciousness and focus on continuous improvement if they are to manage their costs successfully.

Stop the firefighting attitude

Integrated activity planning needs to be strengthened. Often, operational decisions are made in a reactive rather than proactive manner; as a consequence, avoidable costs are incurred on rework and last-minute modifications and orders.

A stronger focus on demand planning is required to prevent idle resources from incurring costs and better anticipate workload and resource requirements. Accenture Strategy recently helped an oilfield services provider reduce its asset base by 30 percent without lowering its service-delivery standards. At the core of this exercise was the set-up and roll out of a centralized demand planning group to forecast demand requirements, integrate work programs and optimize activity planning. Better visibility resulted in more effective, data-driven decision-making.

Enforce accountability and ownership

A culture of accountability and clear cost ownership should be reinforced. The lifecycle of E&P projects is such that individuals involved during one phase of a project might be reassigned during the next phase. Single point ownership and accountability can become diluted as the project evolves; as a result, teams sometimes make decisions that have short-term benefits but that destroy long-term value. Strong project governance capabilities are critical. Conducting periodic project-assurance reviews and setting up phased milestones for investment decisions will help ensure that capital is only committed to activities with justifiable business cases.

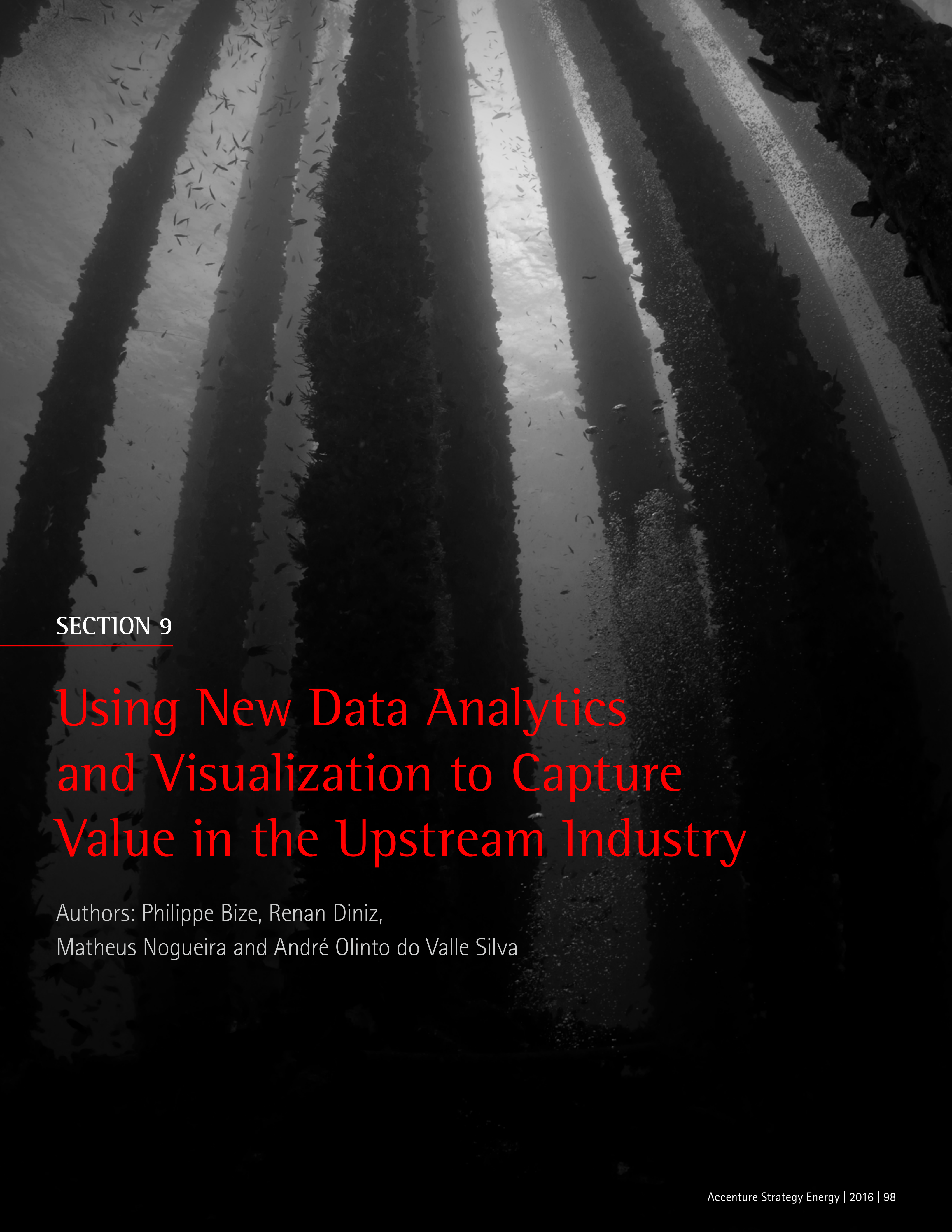
Reduce organizational inefficiencies

Over the past decade, efforts to build incremental production and tackle increasing field complexity have driven companies to expand their operations significantly, in the face of rocketing salary inflation and inefficiencies in some regions. In many cases, these companies have ended up with large, complex organizational structures, in which roles are duplicated, lines of accountability are blurred and inefficiencies are common.

Companies should aim to establish lean organizational structures that clearly delineate responsibilities and enhance the free flow of timely and accurate information along the chain of command.

Management systems should be established to support data-driven decision-making and increase performance visibility. Operational reports should not just be a data dump or a rehash of historical events; they should be forward-looking, highlighting current performance and risks to future delivery. In a low oil-price environment, stronger performance management is essential.

No one knows how long depressed oil prices will last, how they will affect the industry or whether the oil price will return to recent highs, of nearly $115/bbl. But one thing is certain: a more sustainable approach to cost management—embracing new ideas and, indeed, a new mindset—is needed. Companies bold enough to change will be those that thrive.



SECTION 9

Using New Data Analytics and Visualization to Capture Value in the Upstream Industry

Authors: Philippe Bize, Renan Diniz,
Matheus Nogueira and André Olinto do Valle Silva

Data is king in oil and gas, and that is something the industry has long recognized. For example, in its quest to accurately determine reservoir potential and maximize recoverable oil, the industry has pioneered many highly successful data-intensive applications—from wireline logging to seismic modelling. Business decision makers, however, struggle to fully use the resulting wealth of information.[1]

As E&P operations have become exponentially more complex, the volume of data that companies must deal with has soared. Worldwide, sensors now generate upwards of 1 petabyte daily from offshore rigs alone[2], enough to fill more than 2,000 average-sized hard drives (500 GB) every day. While, on one hand, this data powers robust reservoir engineering and production management, on the other, managerial decision makers often lack visibility on basic information such as operating costs or the daily use of logistical resources. This is because data collection is typically scattered across many systems that tend to be specialized for a single technical function, such as ERP systems for finance, drilling scheduling systems, and logistics planning systems. The lack of integration deprives cross-functional decision-makers of information that can help them gain valuable fact-based insights that could dramatically improve their operations.

The result is an unfortunate paradox: an industry that arguably pioneered the Big Data concept for reservoir evaluation and production management now lags in the use of information for business decisions. This lack of data use has even greater implications in today's low-oil-price environment, which is exerting considerable pressure on upstream companies to optimize capital expenditures and improve current assets' operating efficiency.

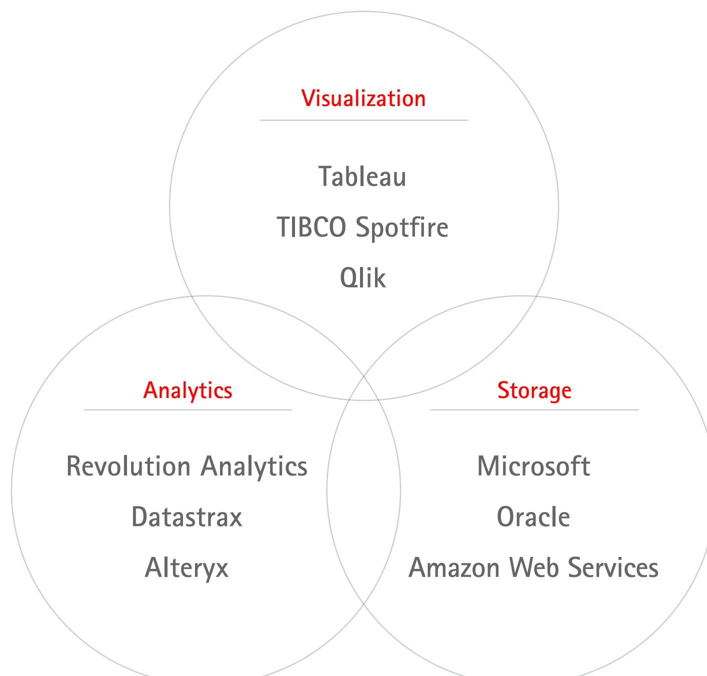
To be sure, oil and gas companies know they can use analytics to gain insights into ways to improve operations and investments. But many are reluctant to embark on projects to develop the necessary analytics capabilities. They fear such projects will be expensive and will disrupt current operations, and may not generate the desired ROI.

While it is true that IT transformations can be long, expensive and complex, development of analytics capabilities need not be. In fact, a new generation of data analytics and visualization tools can help oil and gas companies wring significant business value from their data at a lower cost and with minimal disruption.

Next-generation data analytics and visualization

Such systems fall into three overlapping categories: storage, analytics, and visualization (Figure 1).

Figure 1: The three overlapping categories of next-generation data storage, analytics and visualization tools



[1] See chapter 5 of Energy Perspectives, "Using the oil price crisis to transform in North America: Five fundamental breaks from the past."
[2] Considers circa 800 active offshore rigs worldwide and 1 – 2 TB of daily data per rig – Sources: RigLogix, January 2015, Cisco – A New Reality for Oil and Gas, April 2015

Storage systems enable companies to migrate their data centers to online external clouds, thus increasing agility and computing capabilities. The analytics category refers to a diverse set of data processing technologies. Visualization tools produce interactive dashboards that businesses can use to display various types of data and can share across an entire organization. In practice, many software companies provide solutions that span all three categories.

Among these services, visualization tools such as Tableau, Qlik and Spotfire are the most accessible to business managers unfamiliar with IT software. With recent innovations, these tools can reduce development times, integrate multiple databases with minimal disruption to existing architecture, and analyze large volumes of data (Figure 2).

One of these tools' biggest advantages is that building visualizations does not require IT-specific backgrounds or programming skills. They are optimized to process very large amounts of information and can integrate data from disparate sources. In short, these new tools make it easier to capture and transform data into actionable insight.

Additionally, a company can quickly set up pilot programs to demonstrate potential optimization benefits. And, in recent years, these tools have begun to incorporate built-in capabilities previously present only in analytical software—such as regression analysis, prediction, and spreadsheet-like computing functions. Yet they remain user friendly.

These characteristics can help oil and gas companies avoid the challenges they have traditionally faced when seeking to wring additional value from their data. One of these is access. Data is often spread out across isolated datasets without common standards and must be extracted as one-off queries. A second is that data is often displayed in non-interactive formats, which limit the analyses to a specific scope. Inherent in both of these challenges is that it will be difficult for a company to modify and update analyses. A third challenge is that complex software makes data processing impossible for business managers without relying on a dedicated IT task force.

Combined, these difficulties translate into a long development cycle—the typical timeframe ranges from months to years—and a feeling among managers that they are "drowning" in big data.

Figure 2: Next-generation tools enable more effective and less resource-intensive development of analytics solutions

Software	Key functionalities	Benefits
Tableau First version: 2007	• No need of IT-specific backgrounds or programming skills for development • Capability to display data in interactive dashboards that can be shared across an entire organization	Reduced lead times
Qlik First version: 1995	• Optimized to process very large amounts of data • Capacity to get data from very disparate source databases across organizations	Reduced investments
TIBCO Spotfire First version: 1996	• Built-in analytic capabilities such as regression analysis and prediction, in addition to spreadsheet-like computing functions	Faster learning curve

In comparison, next-generation data analytics and visualization tools give oil and gas business managers an easy, quick and cost-effective way to identify and capture opportunities to create economic value from their data. In fact, agents close to the economic and operational realities of the oil and gas business can develop data analysis solutions that lead to improved economic performance in as little as two to three months.

A new approach to oil and gas analytics

The key to achieving such results is a new approach to analytics development. As illustrated in Figure 3, this four-step approach is focused on speed to value. It does not initially require a new data architecture, and it relies heavily on prototyping to begin generating benefits quickly. A number of oil and gas companies have successfully deployed this approach, as we highlight in the following examples.

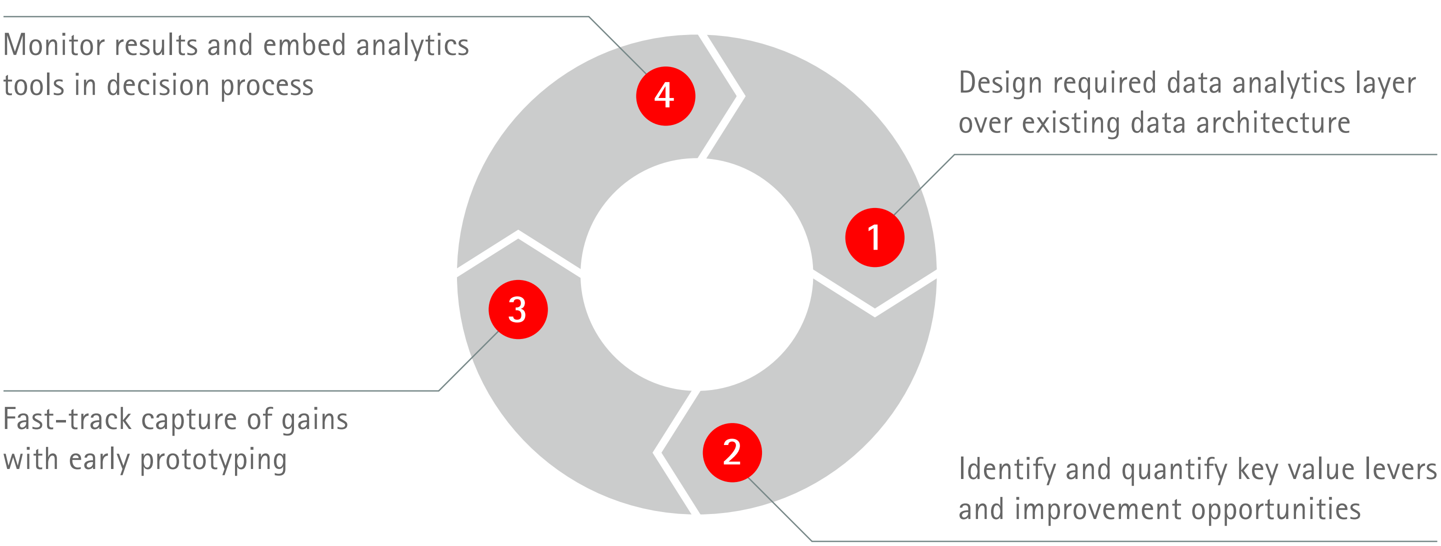
1. Design required data analytics layer over existing data architecture

The first building block for a leaner approach to oil and gas operations analytics is to design a data analytics layer directly over the existing data architecture. Doing so can reduce lead times from more than six months to a few weeks. It also leverages an important feature of next-generation data analytics and visualization tools: the ability to plug into the existing IT infrastructure and immediately integrate databases that vary by location (wellsite versus headquarters), function (operations, logistics, HSE, and finance), and source system.

A leading North American oilfield service provider recently benefited from this "light touch" approach. The company used different kinds of proppant for its fracking operations and needed insights into its supply costs at a granular level. With demand for proppant skyrocketing, the organization was under intense pressure for timely delivery to well sites. Unfortunately, lack of visibility into its cost structure and decentralized decision making had led to delays and shortages, high costs, and a very limited understanding of the problem's root cause. Further complicating the problem was a complex and decentralized logistics and distribution network, which left the company with little insight into cost lines and cost drivers and a fragmented information flow that made compilation and analysis difficult.

In response, the company established intelligent relationships among several data warehouses, including third-party systems, financial databases, local activity logs, and public oil and gas activity reports. Using minimal IT infrastructure and manpower, the company also integrated data from various parts of its supply chain network—including purchase order lists, rail and logistics databases, inventory registers, and invoice and contract records. By thus integrating data from previously isolated islands of information, the company paved the way for future analysis and supply chain optimization. Within 2 months, the company was able to define a set of improvement initiatives to reduce supply costs by USD 40 million—10 percent of baseline expenses.

Figure 3: A new approach to data value creation



A second company, an offshore drilling contractor in Brazil, used a similar approach to exert greater control over its inventory levels. With its existing inventory tracking software needing significant improvement, the company built an updateable external database for validating and reconciling inventory data—rather than engaging in a lengthy process to modify the software. By not altering the existing architecture or superseding the existing data capture systems, the project team gained ready access to key data in a matter of days.

2. Identify and quantify key value levers and improvement opportunities

Once a company collects relevant data, it can use next-generation visualization tools to quickly and more comprehensively analyze large amounts of data. In particular, interactive dashboards make it possible to immediately explore data at various levels of granularity. For instance, visualization tools' "slice and dice" features enable users to zoom in and out of their data, thus identifying key value levers and improvement opportunities much more quickly.

Using the tools in this way can be a boon for upstream business managers with P&L responsibility, who often find it time consuming to keep track of every single cost driver on their income statement. That is what one oilfield service provider in North America experienced when it recently built cost trees using next-generation visualization tools. These cost trees consisted of a hierarchy of costs that allowed analysis of drivers over time. The company designed 50 dashboards in only three months, which enabled it to quickly drill down on all its cost lines and value drivers. The dashboards revealed more than 70 improvement initiatives, and the system proved so useful it was rapidly implemented across the company's operations worldwide.

3. Fast-track capture of gains with early prototyping

The beauty of this approach is that it begins generating benefits in a few days or weeks, not months or years—as the offshore drilling contractor discussed in step 1 discovered. Even while the company was still developing its new inventory management system, initial prototypes helped prevent unnecessary purchases, thus improving financial performance in a severe cost-cutting environment.

Instead of aiming to develop a complete system at once, the company chose to start by building very simple initial dashboards, testing them with key stakeholders, and incorporating feedback on the processes. After several iterations over eight weeks, the prototype evolved into a full-fledged tool ready to be incorporated into the inventory management process. Importantly, the tool can be easily updated, which increases the likelihood it will continue to have a positive impact on the organization over time.

This "deploy-and-improve" approach allows companies to react quickly to changing conditions. User-friendly analytics and visualization tools make it possible for the company to rapidly develop tools and corresponding processes to inform emerging decisions.

4. Monitor results and embed analytics tools in decision process

While short-term results are valuable, the true measure of a solution's worth is its ability to generate ongoing benefits over a longer horizon. Thus, in the final stage, a company must find a way to embed a sustainable solution into the organization's decision-making processes.

That was the challenge a National Oil Company (NOC) faced in Latin America. The company used the previous stages of our approach to implement a new drilling and completion monitoring tool. The tool was designed to reduce Non-Productive Time (NPT) and improve planning efficiency—and, in the process, help the company remain competitive in a harsher competitive environment.

The tool was not disruptive to the existing IT infrastructure, which favored its quick development, and the dashboards' interactivity made it possible to involve key decision makers. In only two months, the prototype became a permanent monitoring solution within the company's governance, and is now used at various levels in the organization.

A first set of dashboards helped the company leadership perform monthly performance reviews. These visualizations allowed leaders to quickly navigate through key KPIs (slicing and dicing them at will), making meetings much more fact based and efficient, which lead to quicker and more informed decisions. Another set of dashboards helped drilling/asset managers by providing more detailed information—for instance, enabling them to get a much deeper look at each well or type of NPT problem.

A new approach requires a new mindset

As illustrated, companies using the preceding four-step approach can quickly capture value from data while optimizing investments. In fact, the approach can help companies escape the "data analytics paradox" and use the data they already have to improve their operations in the current economic environment.

But merely deploying technology does not automatically create economic value. More specifically, using analytics and visualization tools without the proper business context will not produce insights that optimize decision making. The reality is that successfully implementing a new approach to data value creation requires a cultural shift, a new mindset.

Decision makers leading design

Strong leadership from business teams is critical to ensure that new tools and identified changes will be accepted and implemented throughout the organization. Senior management must be involved in the process, and people from the business functions affected should be included.

IT as a partner

Although IT resources can provide extended capabilities for data analysis, business leaders should not expect IT to take the lead. The emergence of a new generation of analytics, with faster development cycles, makes it possible for IT to work as a partner in prototyping analytics tools, and later, in developing permanent solutions. Business teams and IT work together to test the effectiveness of solutions within operations and corporate governance, and agree on desired functionalities that are both useful and quickly deployable. This helps avoid the typical issues with poorly specified IT projects: high costs, long lead times, and disruption.

Immediate survival—and beyond

Surviving the new era of low prices requires oil and gas companies to view data analytics as one of their most powerful allies. Fortunately, a new suite of technologies promises to help oil and gas companies gain insights into previously invisible aspects of their operations. By tapping into the huge potential of already available data, companies can identify and capitalize on unexpected opportunities to recover their margins.

Looking forward, companies can unlock even greater value. Indeed, the type of initiatives just described represent a specific case of a more general data analytics trend that is quickly penetrating not only oil and gas, but the broader industrial society.

For example, estimates show that productivity gains from the Industrial Internet of Things could increase the rate of productivity growth from approximately 1.5 percent per year in the 2005-2011 period to over 3 percent per year over a span of 15 to 20 years. In fact, the Industrial Internet of Things phenomenon is expected to drive efficiency gains comparable to the Internet itself[3], and it holds massive potential for the oil and gas sector.

The upstream industry must overcome the paradox of having a wealth of data but failing to exploit it to its fullest. By doing so, not only will the industry ensure its immediate survival, but it will also accelerate its adoption of the Fourth Industrial Revolution. ■

[3] See Evans, Peter C. and Annunziata, Marco; Industrial Internet – Pushing the Boundary of Minds and Machines, General Electric, 2012

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Contact the Authors

Muqsit Ashraf
muqsit.ashraf@accenture.com

Philip Askew
philip.askew@accenture.com

Philippe Bize
philippe.bize@accenture.com

Thomas Bonny
thomas.bonny@accenture.com

Raul Camba
raul.camba@accenture.com

Aleek Datta
aleek.datta@accenture.com

Romain Debarre
romain.debarre@accenture.com

Nuri Demirdoven
nuri.demirdoven@accenture.com

Renan Diniz
renan.rios.diniz@accenture.com

Timi Familusi
timi.familusi@accenture.com

Tancrede Fulop
tancrede.fulop@accenture.com

Eric Janvier
eric.janvier@accenture.com

Bruno Lajoie
bruno.lajoie@accenture.com

Stephane Lhoste
stephane.lhoste@accenture.com

Nicole Lu
jingting.lu@accenture.com

Matheus Nogueira
matheus.nogueira@accenture.com

André Olinto do Valle Silva
andre.olinto@accenture.com

Philippe Parlange
philippe.parlange@accenture.com

Olivier Perrin
olivier.perrin@accenture.com

Farooq Qureshi
farooq.qureshi@accenture.com

David Rabley
david.rabley@accenture.com

Jean-Marie Rousset
jean-marie.rousset@accenture.com

Mo Saadat
mohammed.saadat@accenture.com

Manas Satapathy
manas.r.satapathy@accenture.com

Jerome Sevin
jerome.sevin@accenture.com

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